Alaska Gasline PORT AUTHORITY

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Appendix AA - MM

Binder 10

AGIA License Application
November 30, 2007

APPENDIX AA

Valdez Coastal Management Program
Resource Maps
December, 1984

Valdez Coastal Management Program

Resource Maps

CONTAINS CONFIDENTIAL INFORMATION

December 1984

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Maps prepared for Jon Isaacs and Associates by ATECH.

Map Sources

1. City of Valdez. 1979. Inventory Report District Program Phase One, Valdez, Alaska.
2. Alaska Dept. of Fish and Game. 1980 Draft Habitat Maps, Valdez Coastal Management Program.
3. Map adapted by Woodward-Clyde Consultants from: Alaska Dept. of Fish and Game. 1980. Draft Habitat Maps.
4. Alaska State Historic Preservation Office. 1980. Heritage Resource Survey Files. City of Valdez, Community Development Department. 1980.
5. City of Valdez, Community Development Dept. 1980.
6. Alaska Dept. of Natural Resources. 1981. State Public Interest Lands Status Maps.
7. City of Valdez, Community Development Dept. 1980.
8. City of Valdez, Parks and Recreation Department. 1980.
9. Map adapted by Woodward-Clyde Consultants from: Dowl Engineers. 1979. Draft Environmental Impact Statement, Alaska Petrochemical Company. U.S. Army Corps of Engineers, Alaska District. 1980. Electric Power of Valdez and the Copper River Basin.
10. Woodward-Clyde Consultants. 1980.
11. Map adapted by Woodward-Clyde Consultants from: Dowl Engineers, 1979. Draft Environmental Impact Statement, Alaska Petrochemical Company. Woodward-Clyde Consultants. 1980. Field Reconnaissance and Aerial Photographic Interpretation.
12. Woodward-Clyde Consultants. 1980. Field Reconnaissance and Aerial Photographic Interpretation. Woodward-Clyde Consultants. 1981. Valdez Flood Investigation Technical Report.
13. Woodward-Clyde Consultants. 1981. City of Valdez, 1984.
14. Woodward-Clyde Consultants. 1981.

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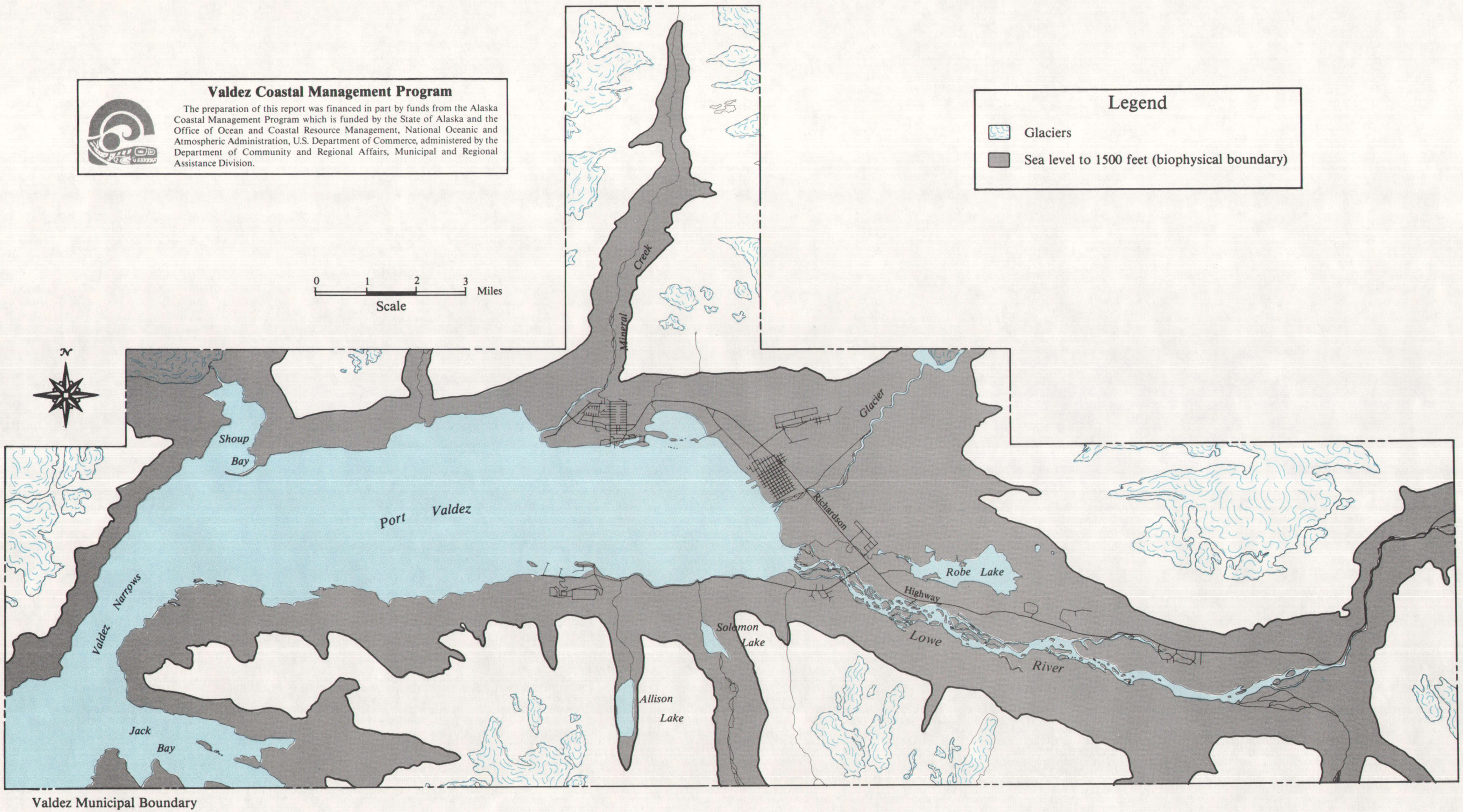

1. Coastal Management District Boundaries

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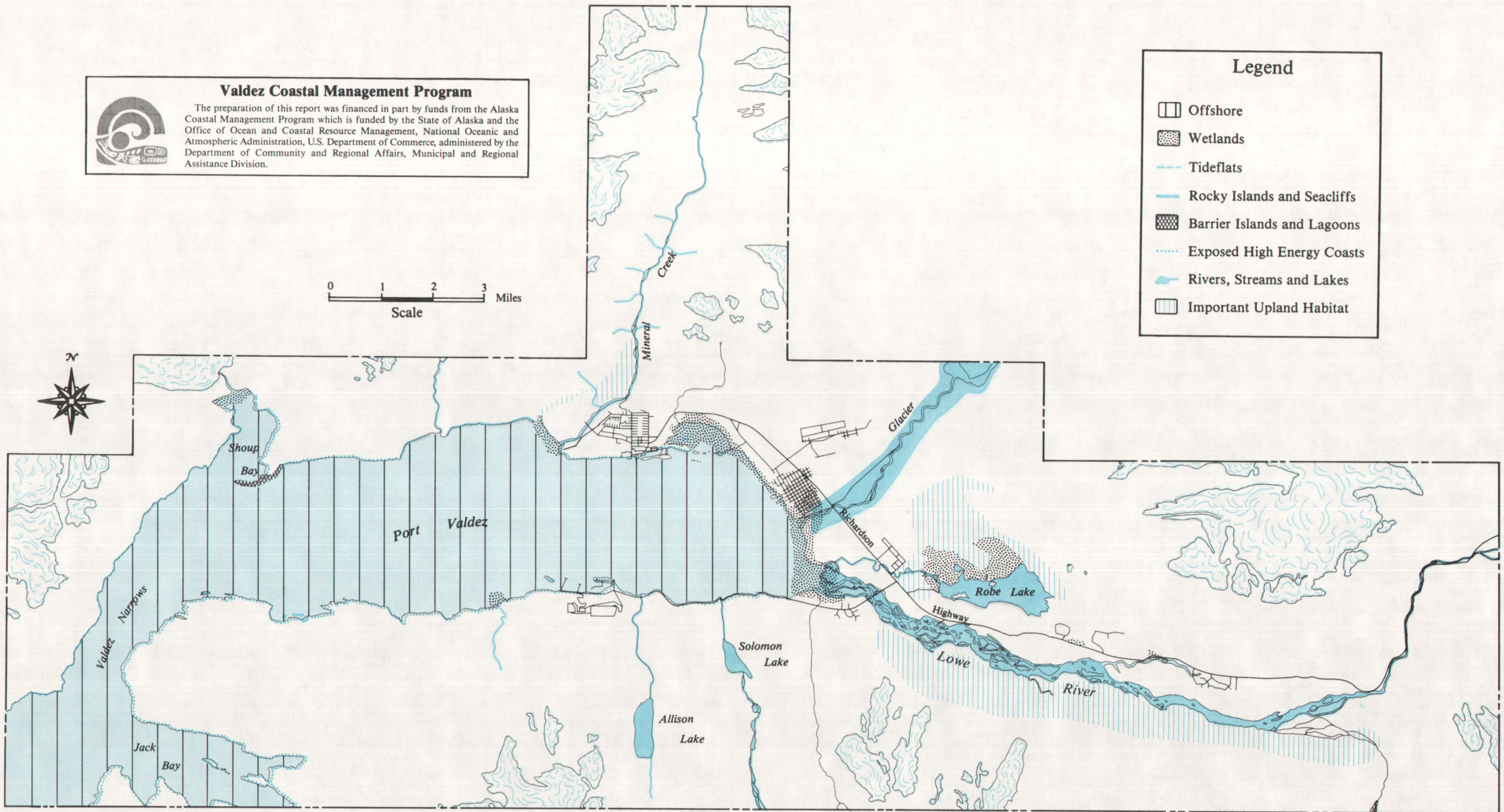

Valdez Coastal Management Program

The preparation of this report was financed in part by funds from the Alaska Coastal Management Program which is funded by the State of Alaska and the Office of Ocean and Coastal Resource Management, National Oceanic and Atmospheric Administration, U.S. Department of Commerce, administered by the Department of Community and Regional Affairs, Municipal and Regional Assistance Division.

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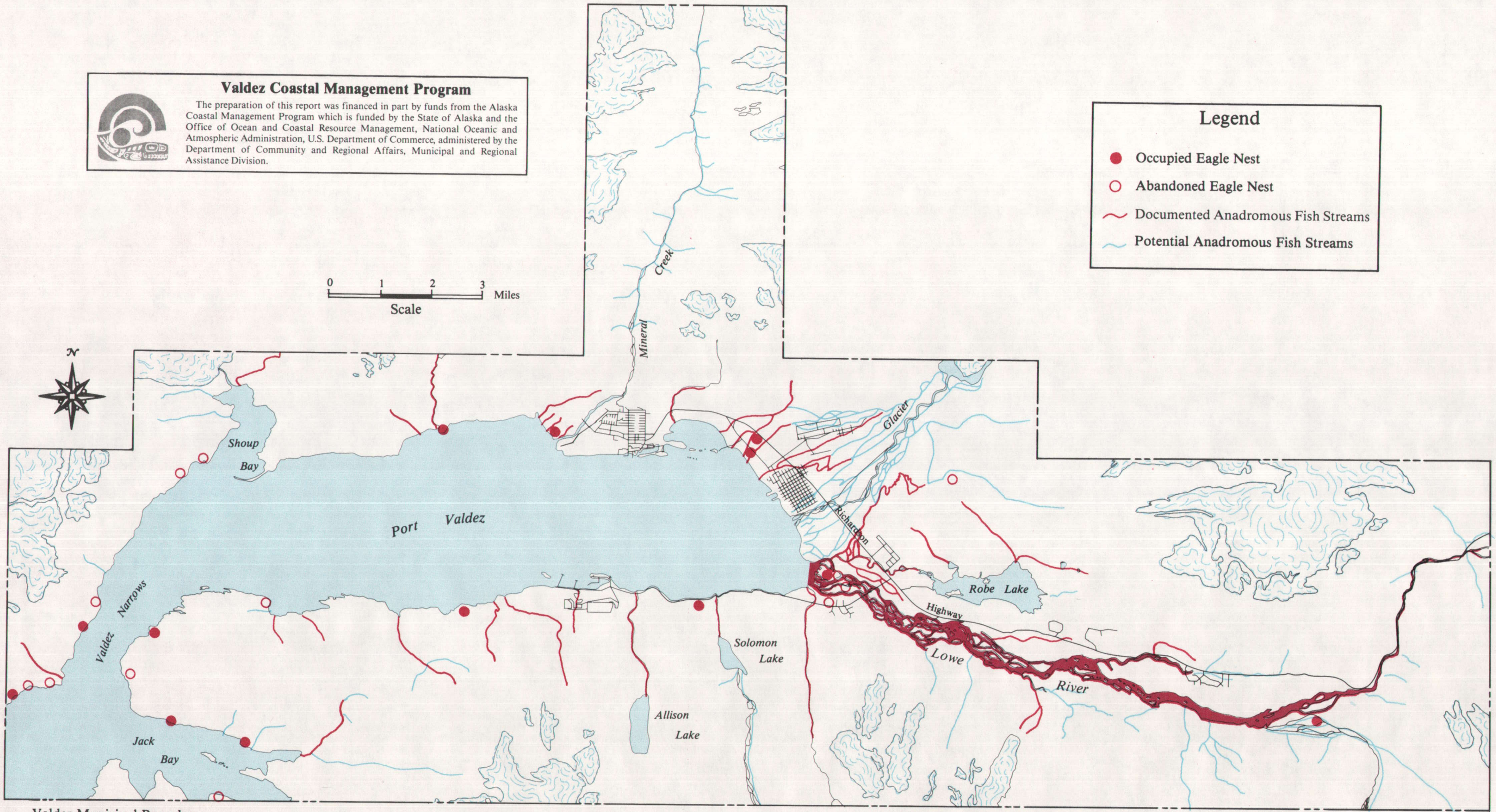
3. Critical Habitats



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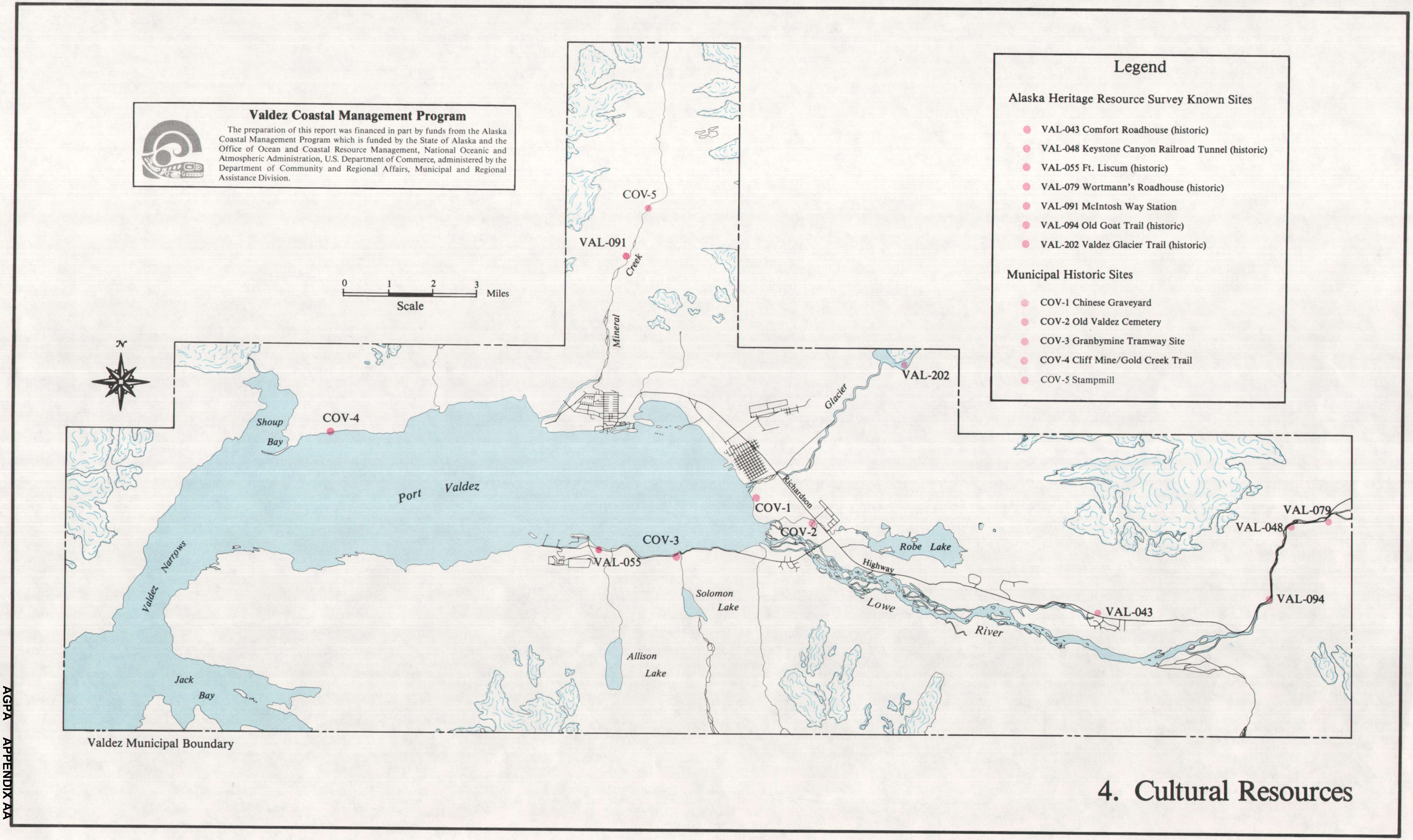

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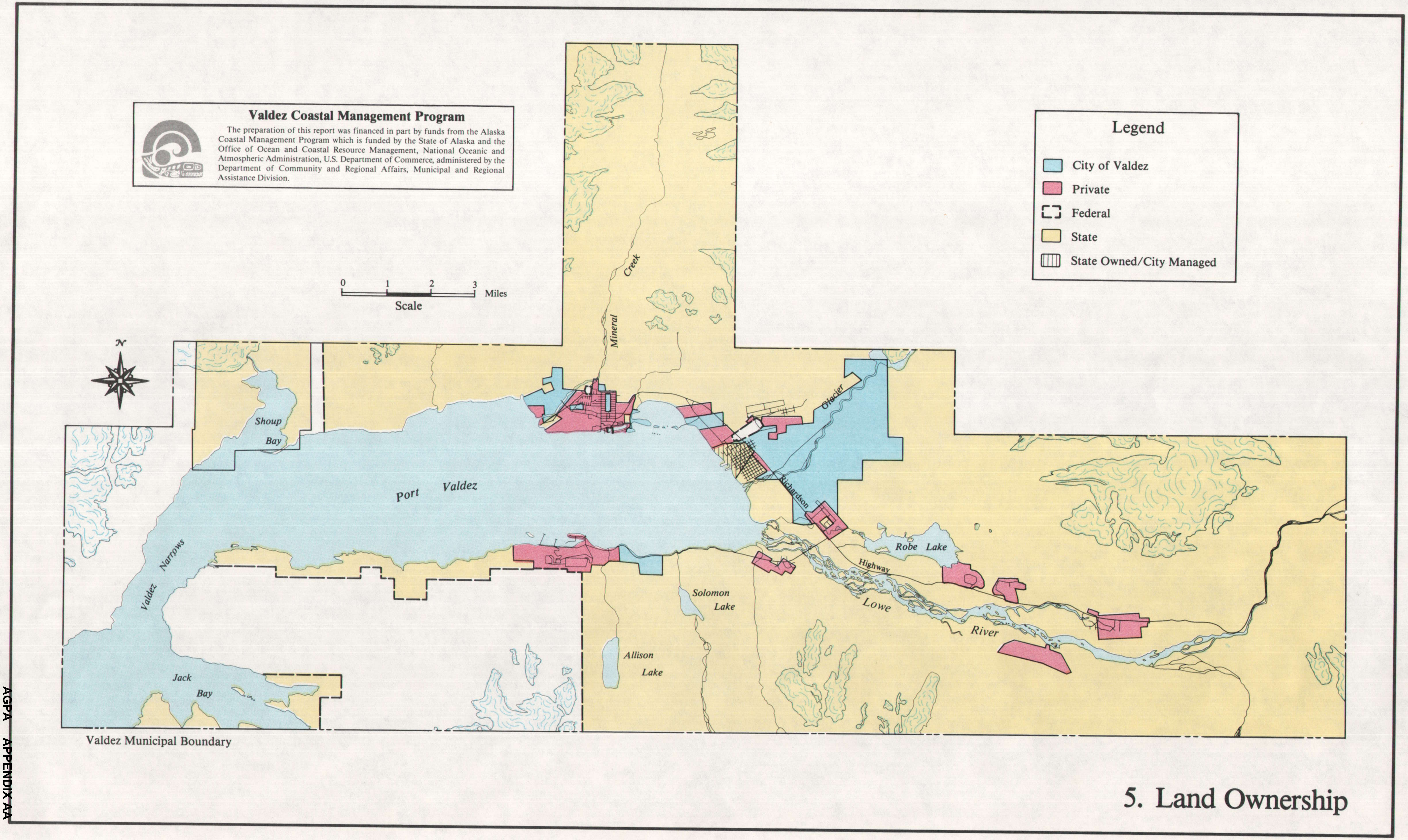

5. Land Ownership

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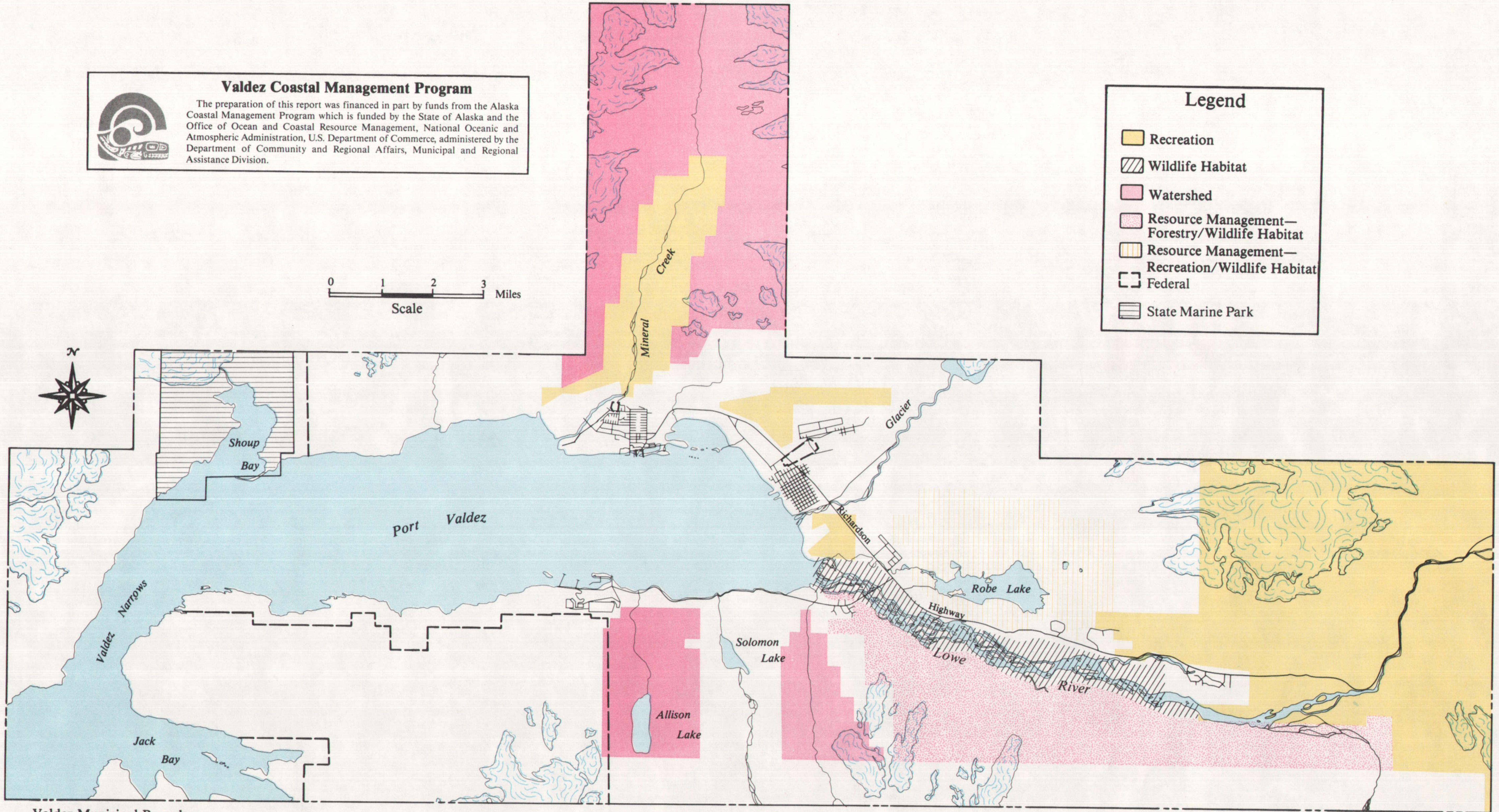

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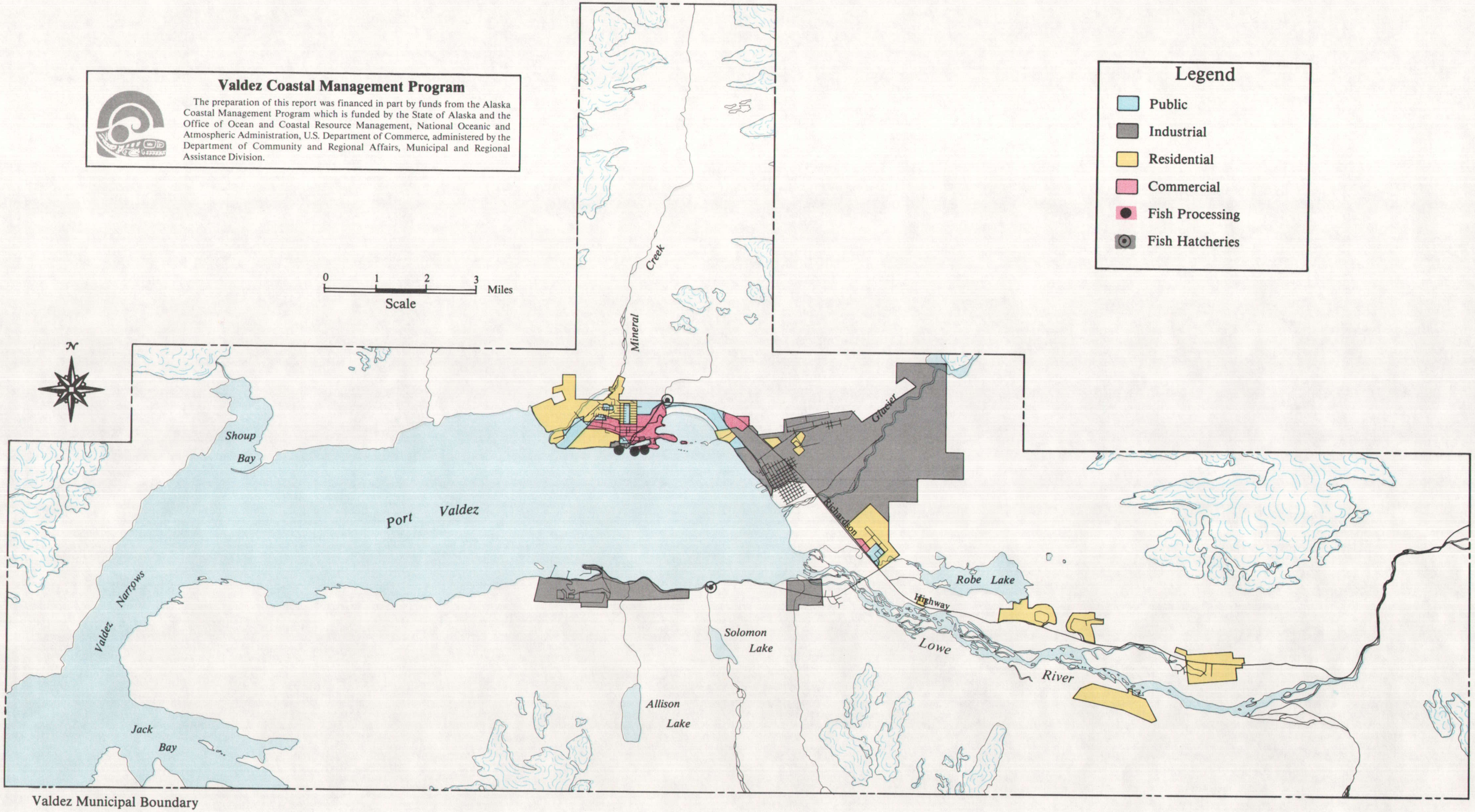
6. State Public Interest Lands



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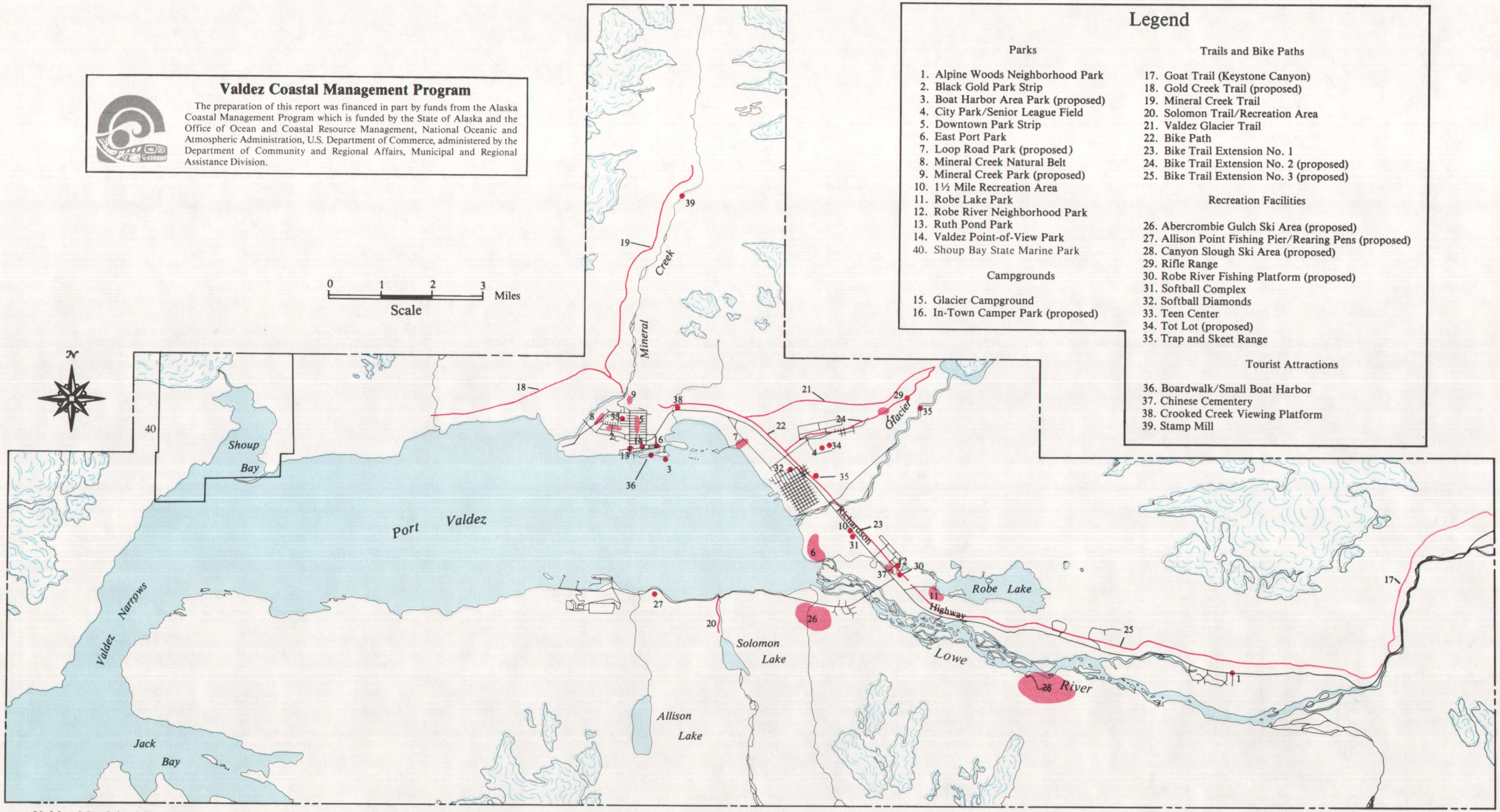

Legend

Parks

1. Alpine Woods Neighborhood Park
2. Black Gold Park Strip
3. Boat Harbor Area Park (proposed)
4. City Park/Senior League Field
5. Downtown Park Strip
6. East Port Park
7. Loop Road Park (proposed)
8. Mineral Creek Natural Belt
9. Mineral Creek Park (proposed)
10. 1½ Mile Recreation Area
11. Robe Lake Park
12. Robe River Neighborhood Park
13. Ruth Pond Park
14. Valdez Point-of-View Park
40. Shoup Bay State Marine Park

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16. In-Town Camper Park (proposed)

Trails and Bike Paths

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18. Gold Creek Trail (proposed)
19. Mineral Creek Trail
20. Solomon Trail/Recreation Area
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22. Bike Path
23. Bike Trail Extension No. 1
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32. Softball Diamonds
33. Teen Center
34. Tot Lot (proposed)
35. Trap and Skeet Range

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36. Boardwalk/Small Boat Harbor
37. Chinese Cementery
38. Crooked Creek Viewing Platform
39. Stamp Mill

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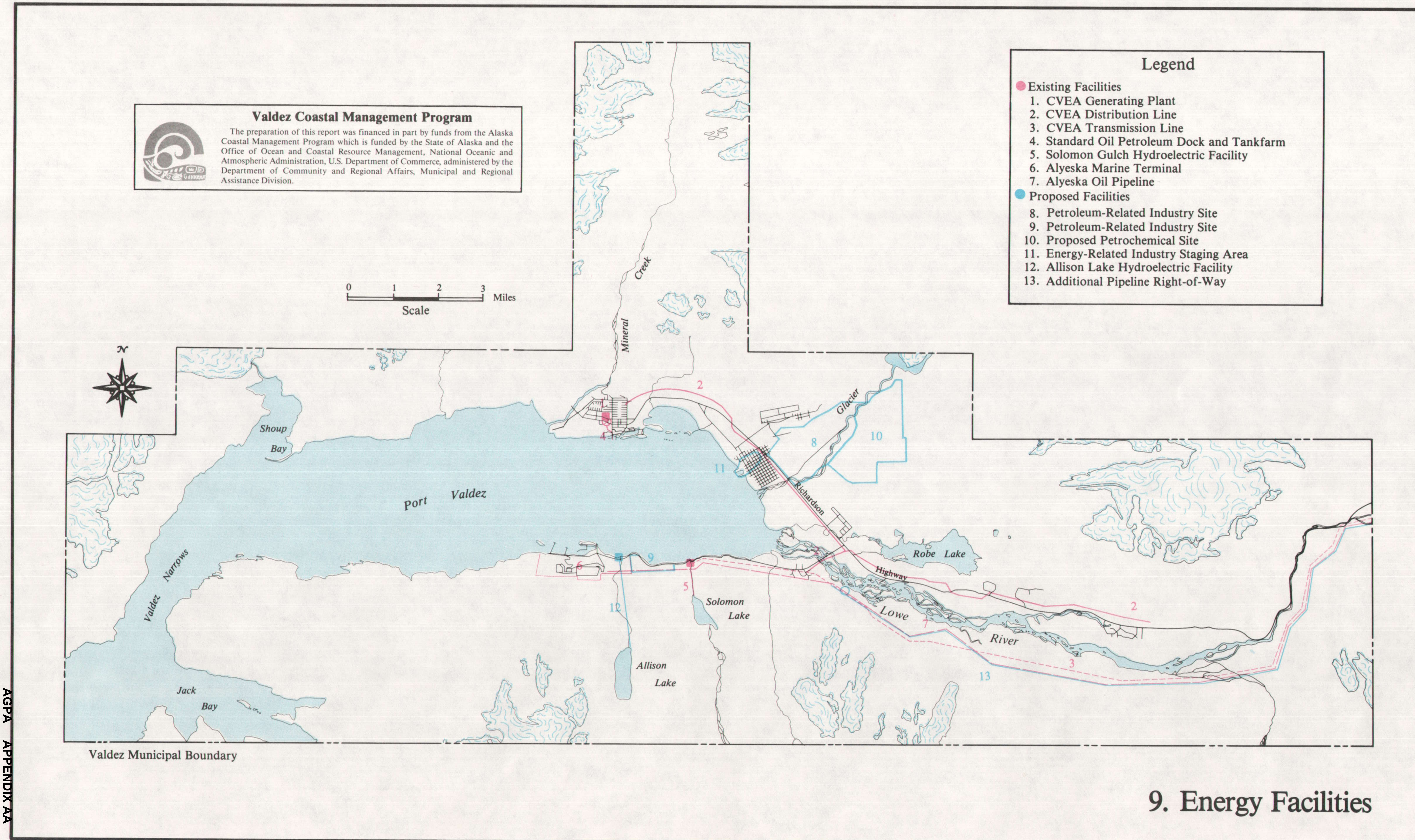

9. Energy Facilities

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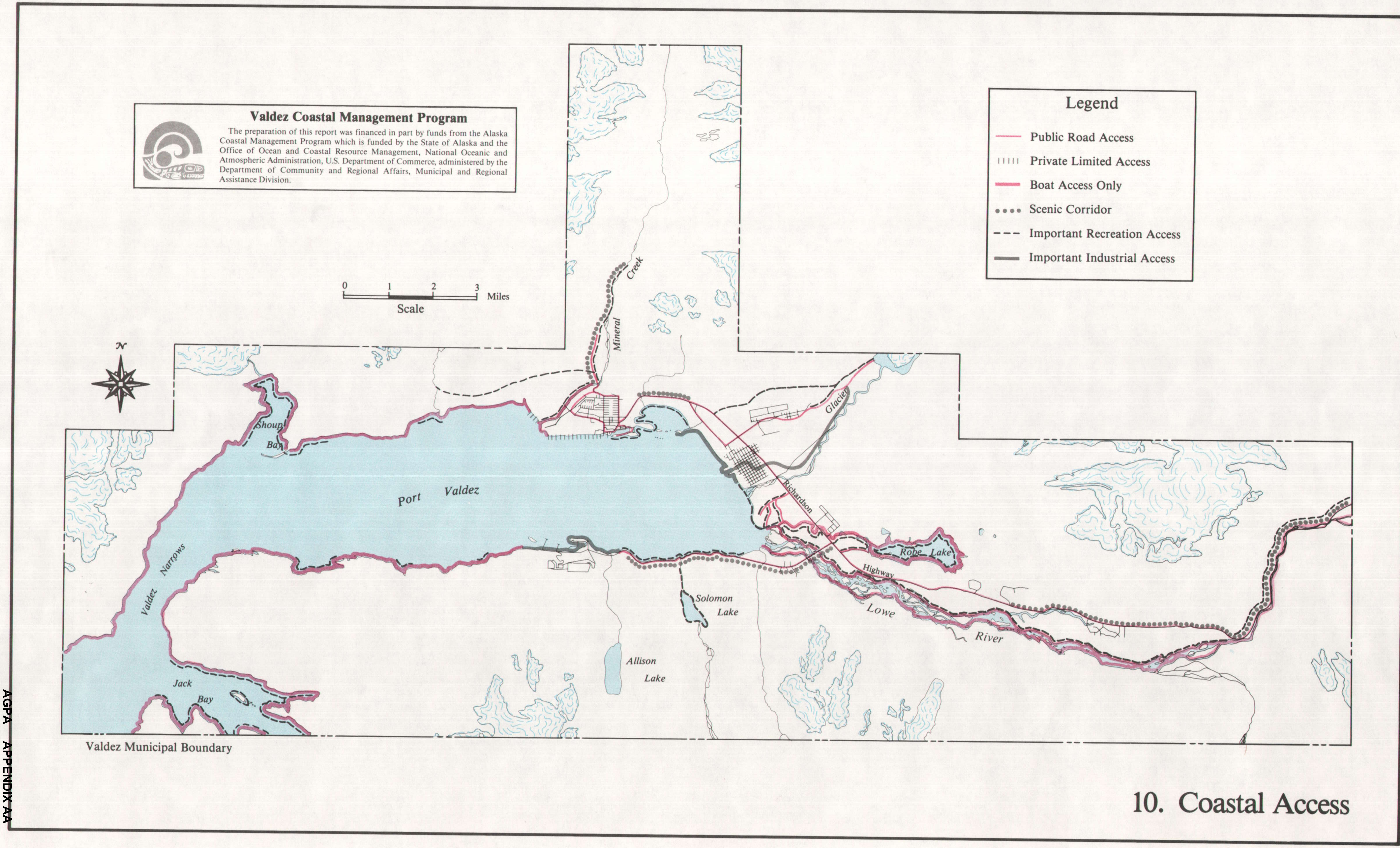

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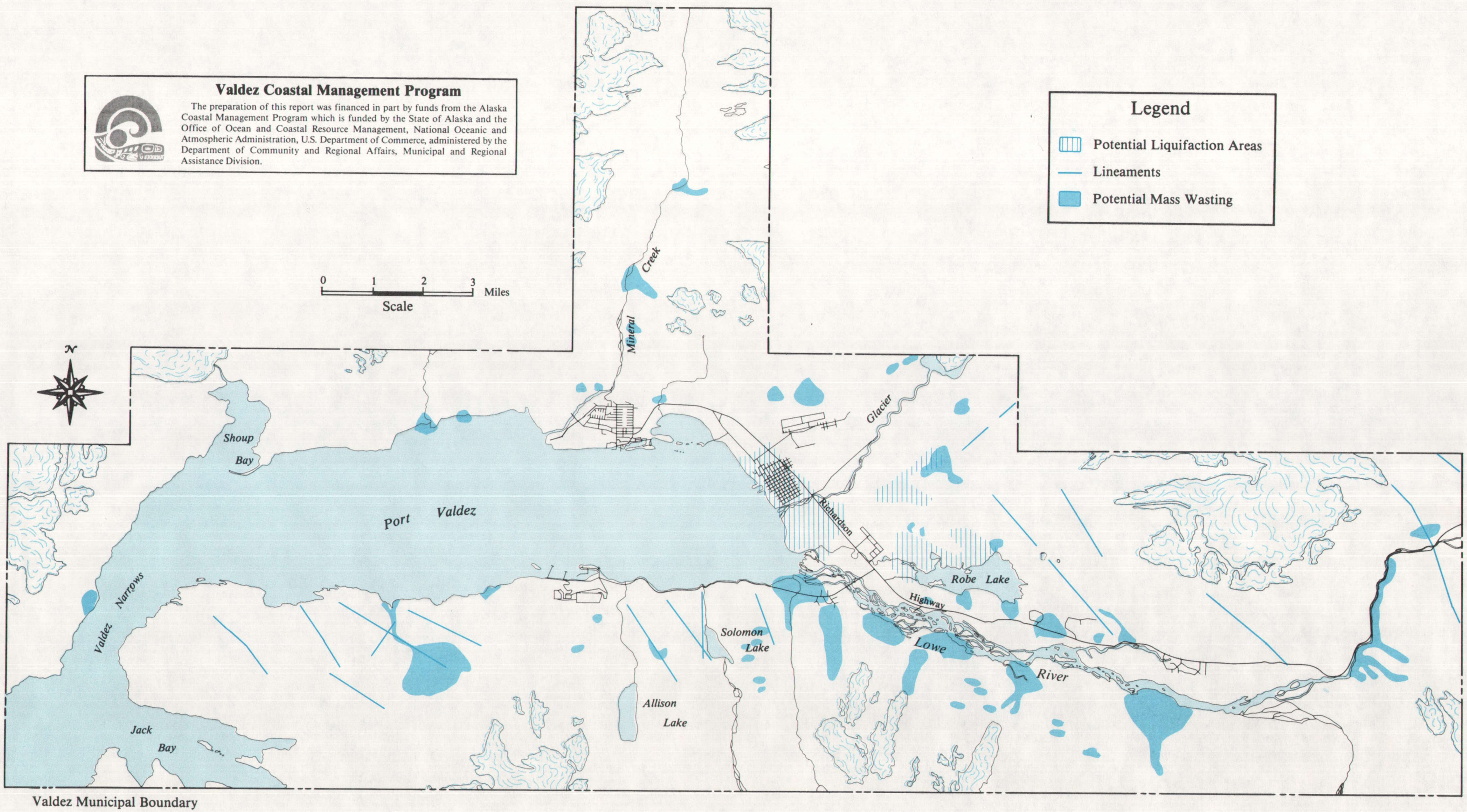

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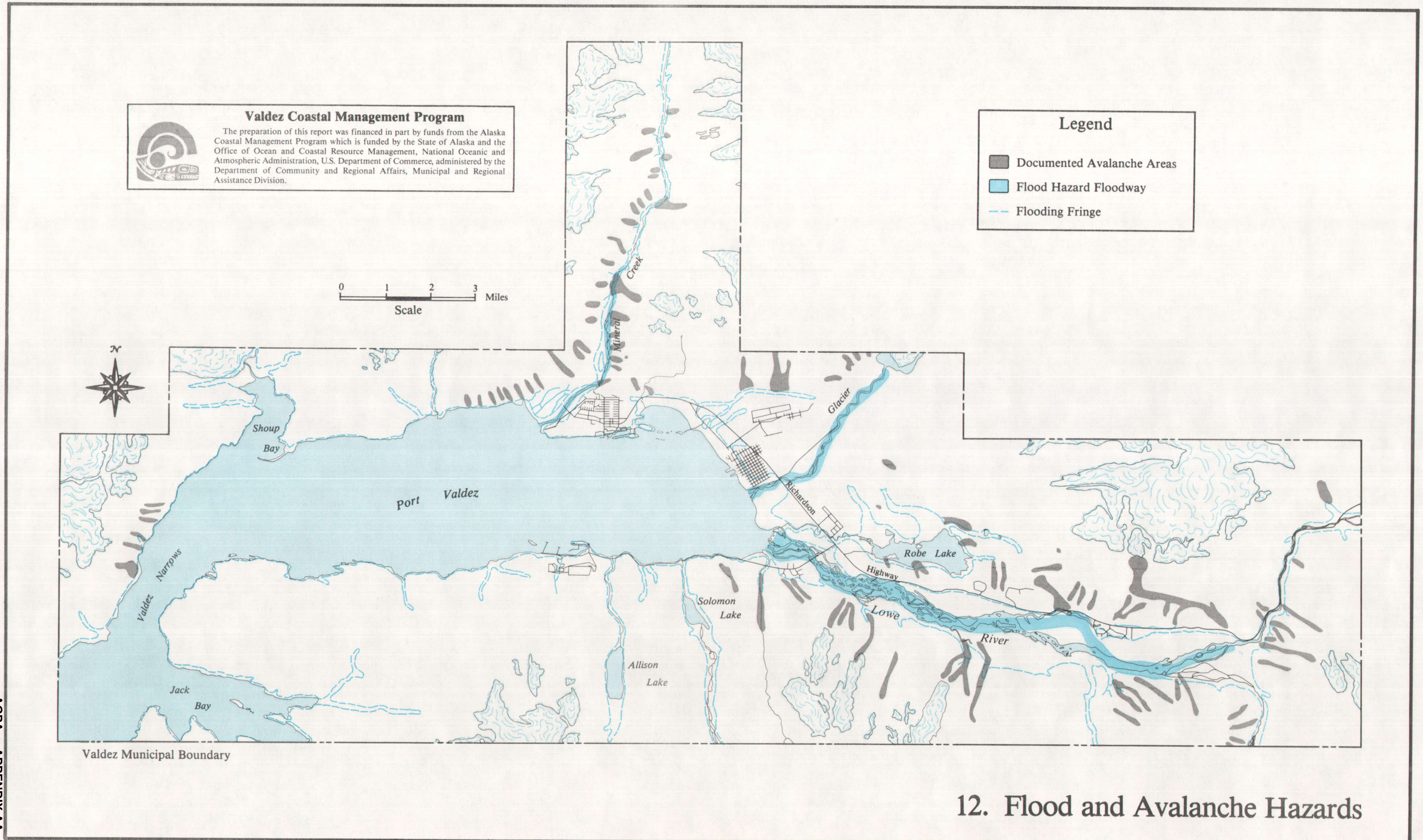

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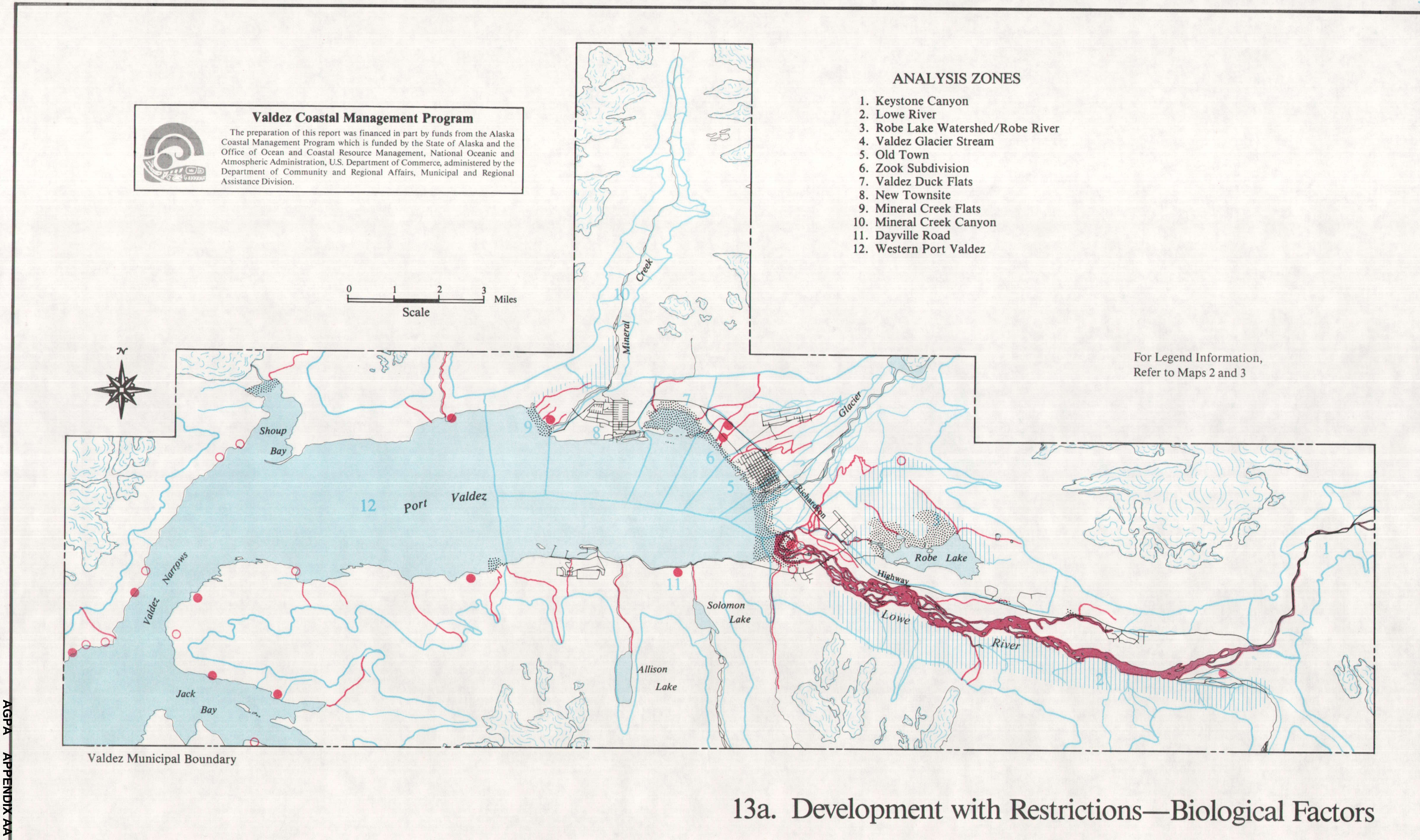

13a. Development with Restrictions—Biological Factors

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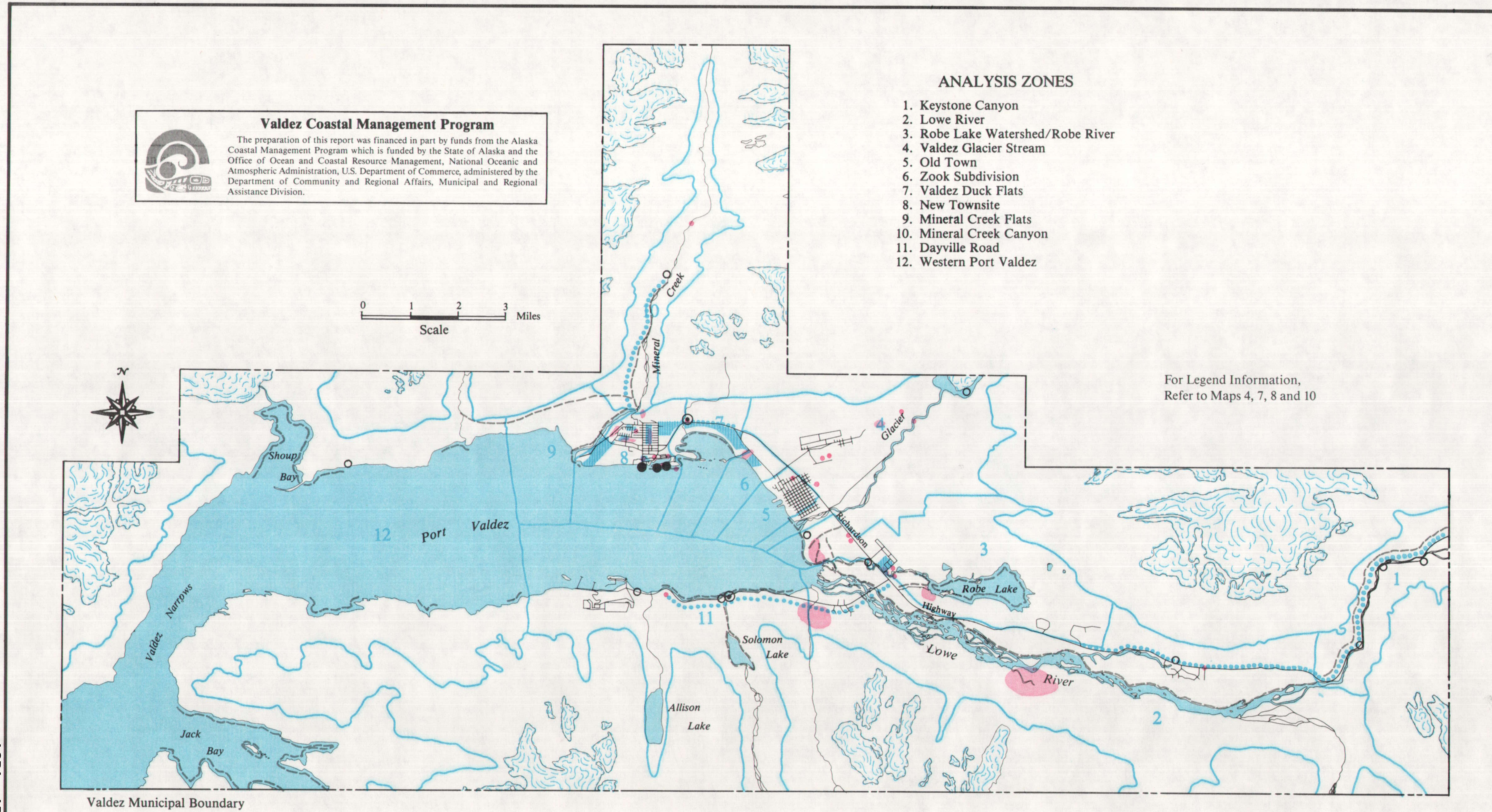

13b. Development with Restrictions—Cultural Factors

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13c.

ANALYSIS ZONES

1. Keystone Canyon
2. Lowe River
3. Robe Lake Watershed/Robe River
4. Valdez Glacier Stream
5. Old Town
6. Zook Subdivision
7. Valdez Duck Flats
8. New Townsite
9. Mineral Creek Flats
10. Mineral Creek Canyon
11. Dayville Road
12. Western Port Valdez

For Legend Information,
Refer to Maps 11 and 12

Valdez Coastal Management Program

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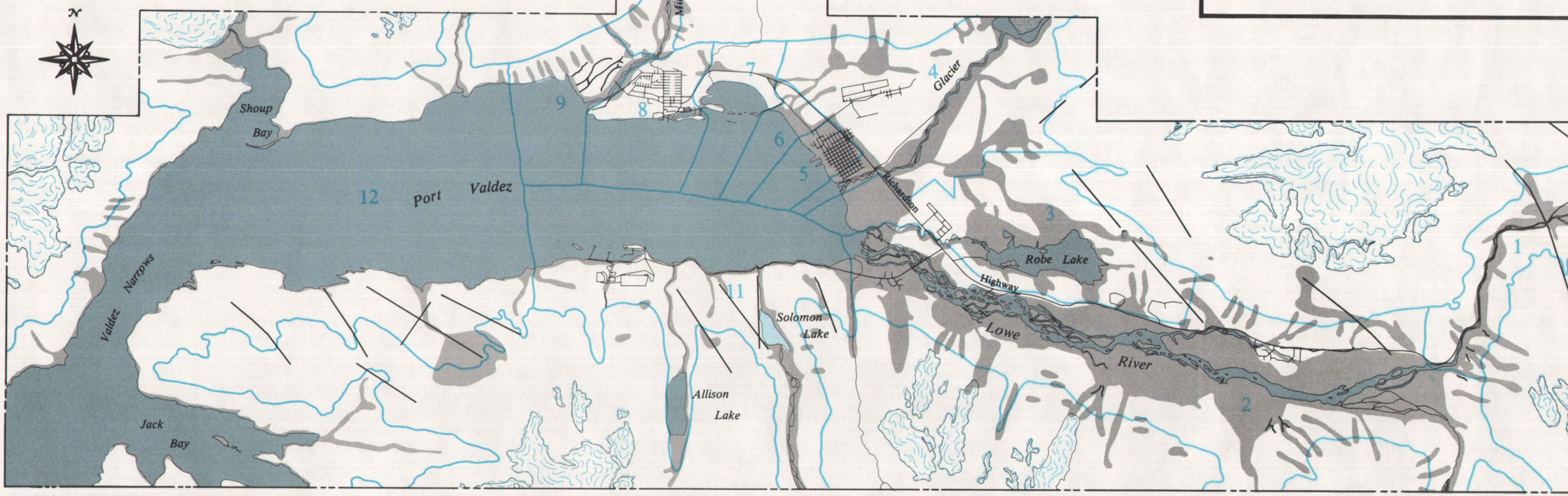
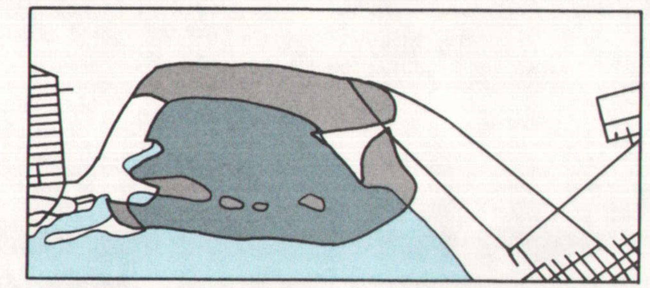


13d.

Duck Flats



*In addition, conservation areas include a minimum of a 25-foot setback from all documented anadromous fish streams.

For Legend Information,
Refer to Maps 2, 3 and 14a

13c. Development with Restrictions—Geophysical Factors
13d. Conservation

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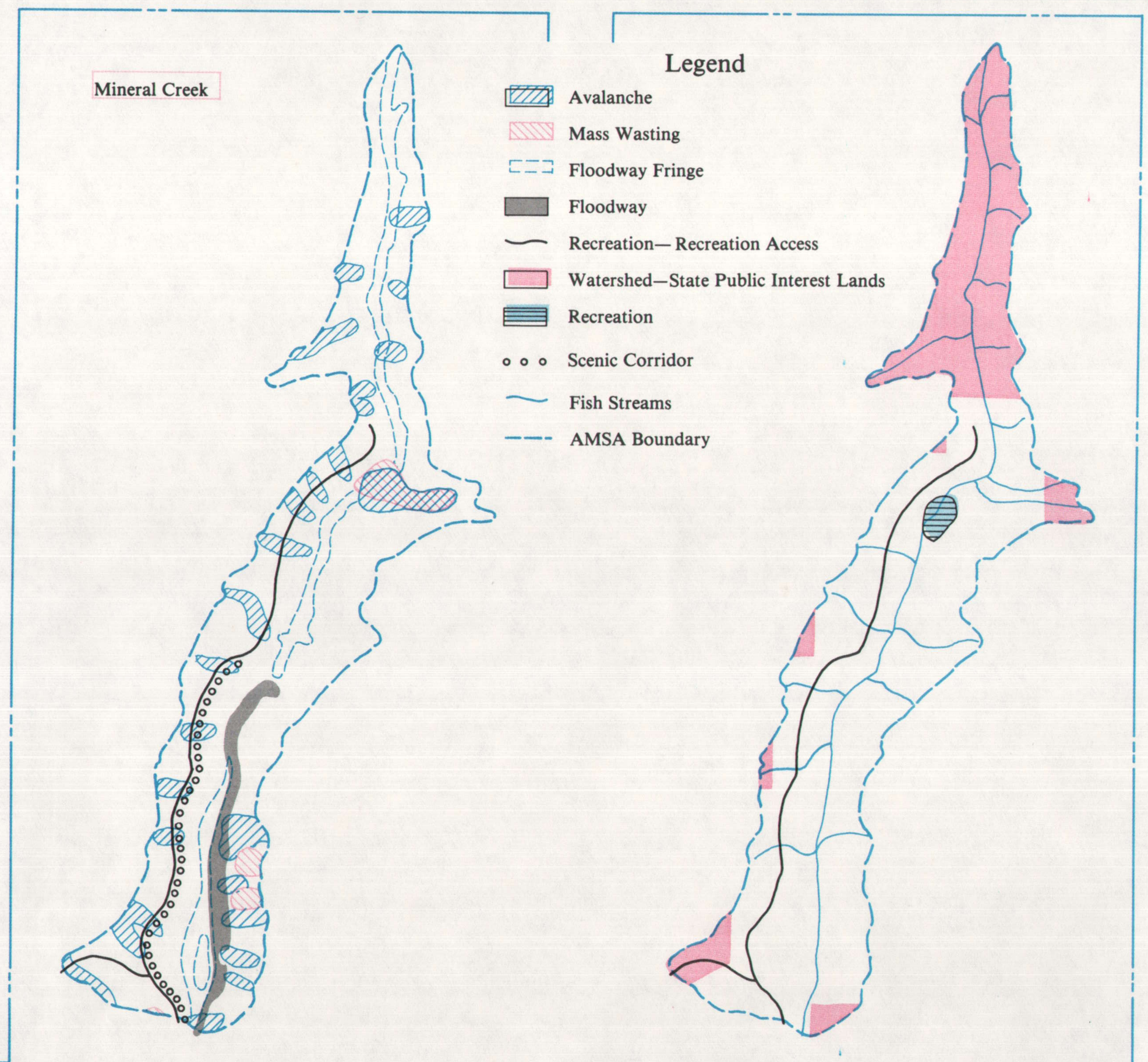

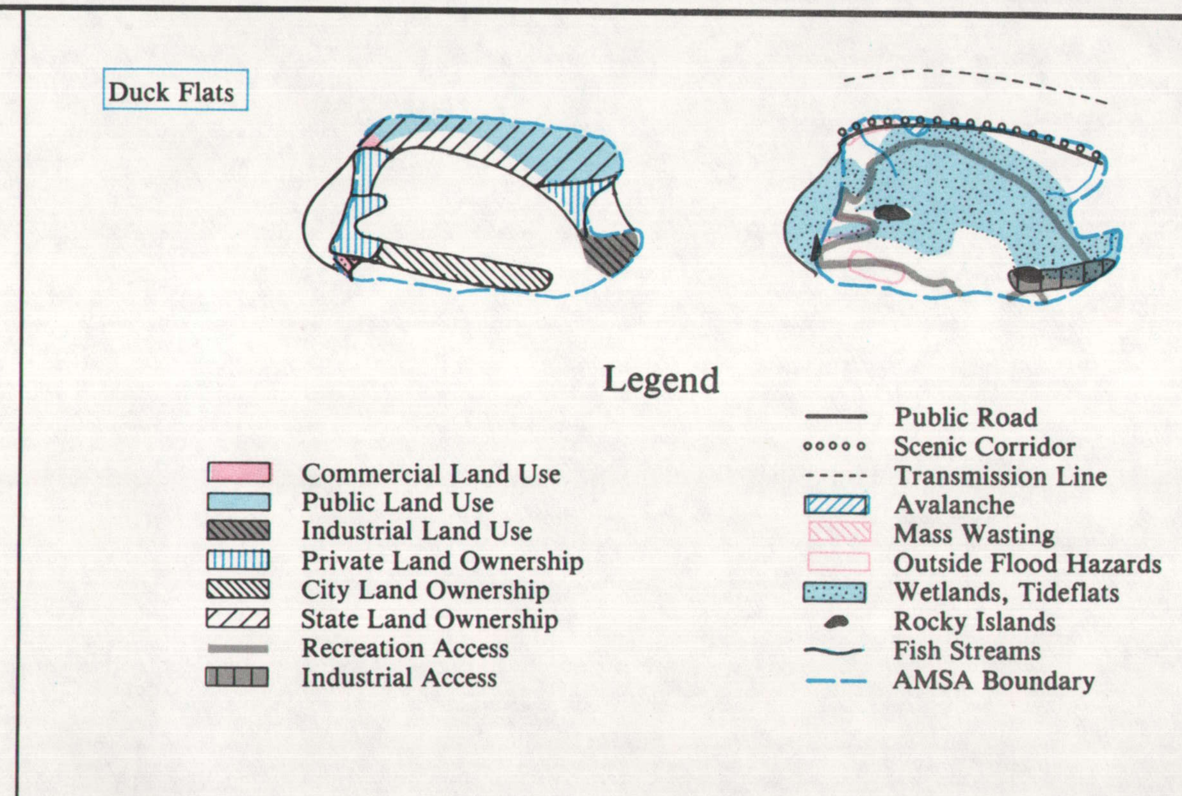

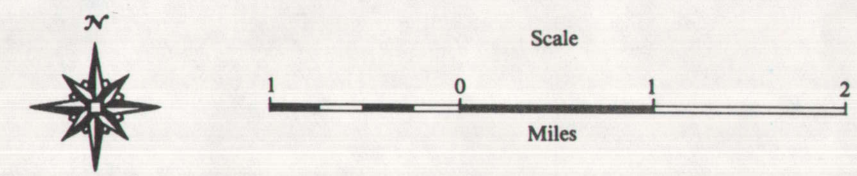

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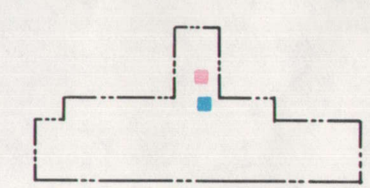
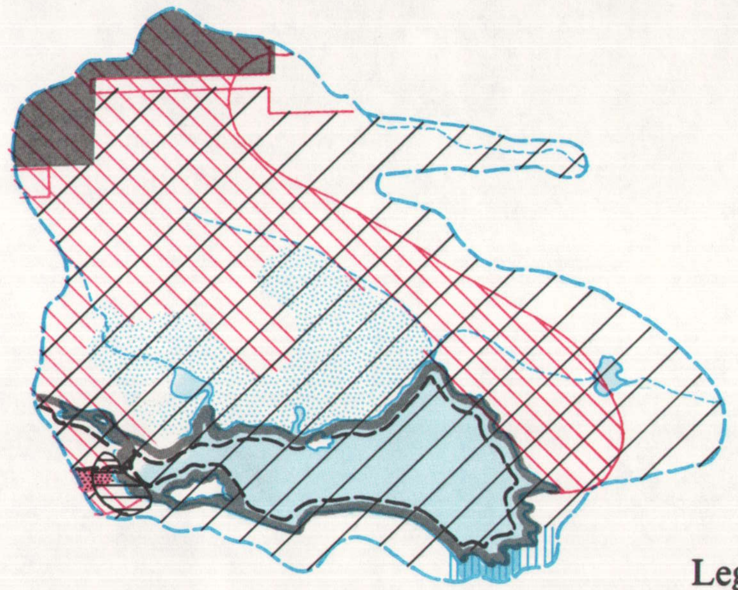


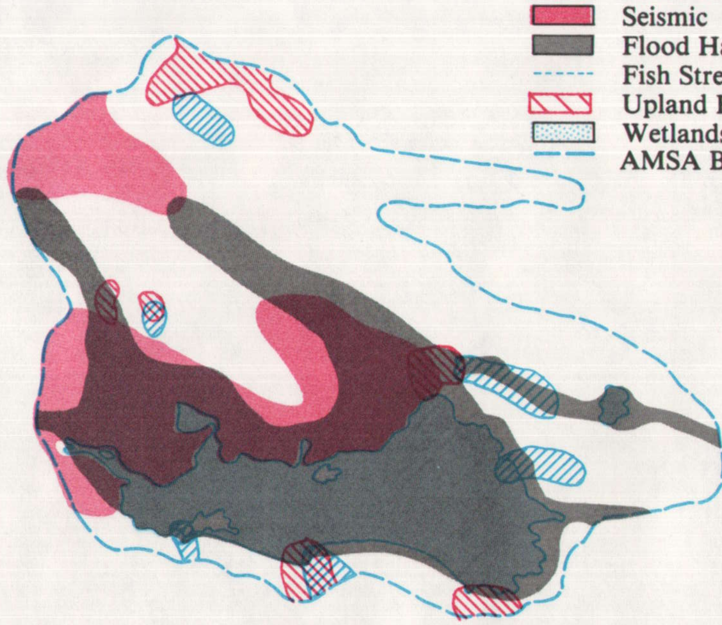
14a. Areas Meriting Special Attention

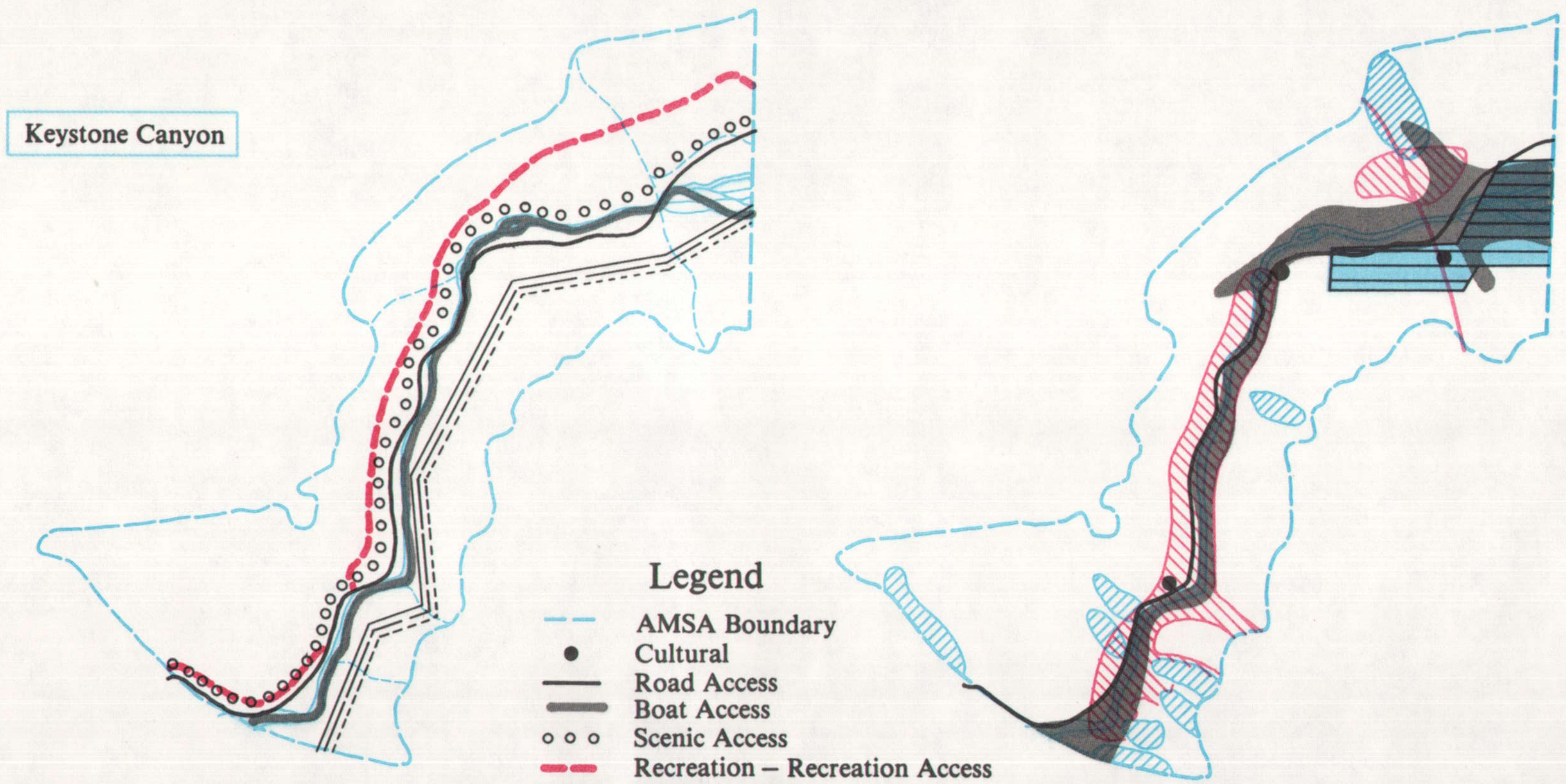


Robe Lake

Legend

- Recreation
- Residential Land Use
- Private Land Ownership
- State Public Interest Lands
- Outside of Management State Public Interest Lands
- Industrial Land Use
- Recreation Access
- Boat Access
- Road Access
- Avalanche
- Mass Wasting
- Seismic
- Flood Hazards
- Fish Streams
- Upland Habitats
- Wetlands
- AMSA Boundary

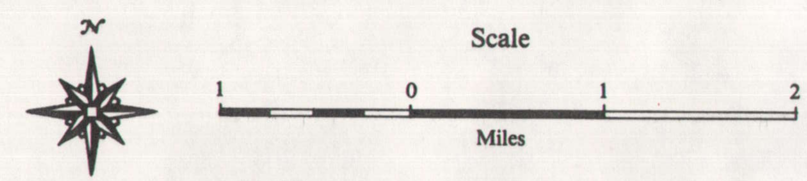




Keystone Canyon

Legend

- AMSA Boundary
- Cultural
- Road Access
- Boat Access
- Scenic Access
- Recreation – Recreation Access
- Energy Facilities
- Fish Streams
- Flood Hazards
- Avalanches
- Mass Wasting
- Seismic
- State Public Interest Lands— Recreation/Wildlife Habitat



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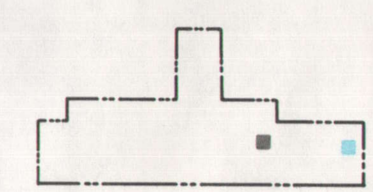
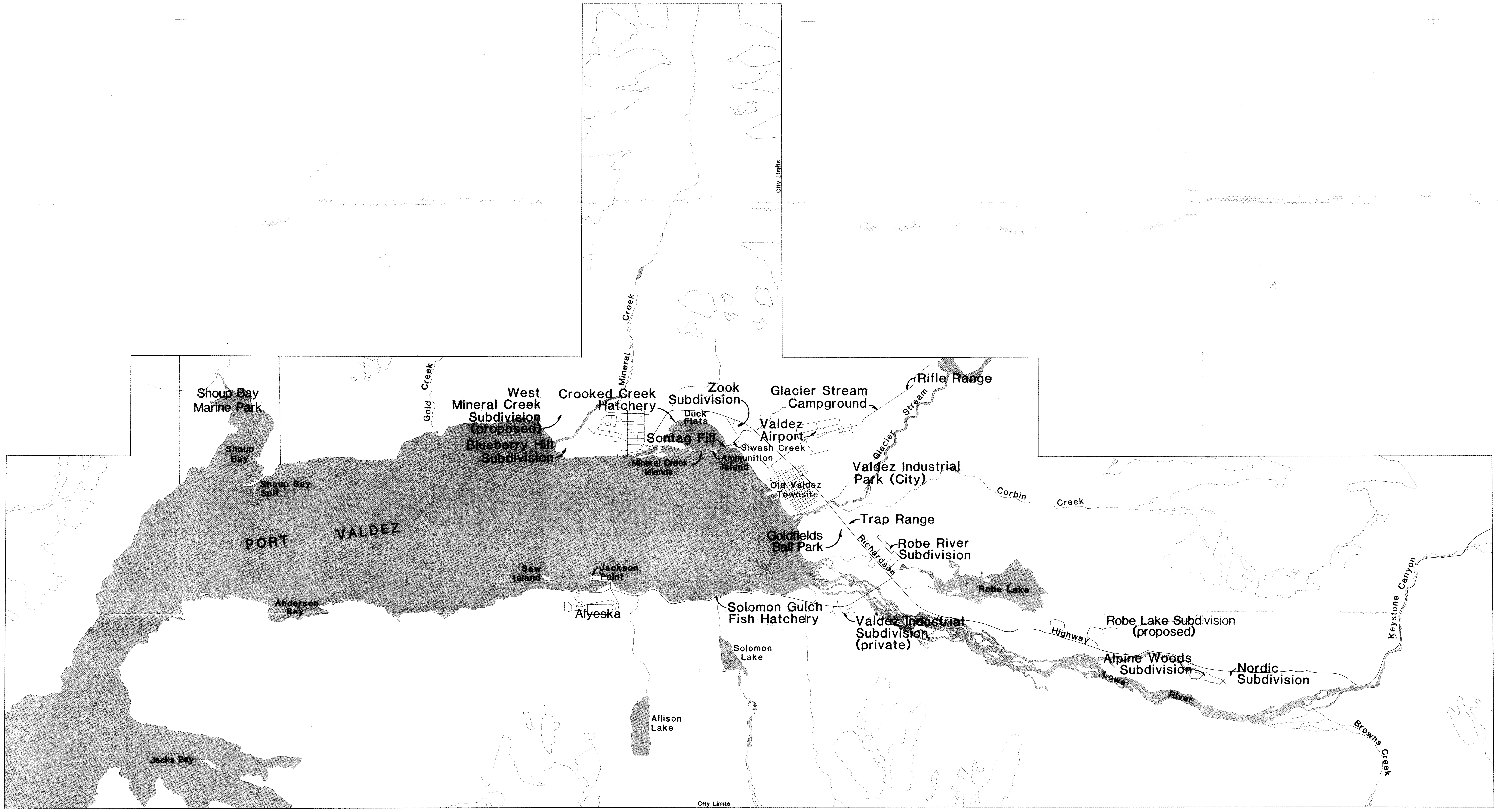


14b. Areas Meriting Special Attention



City of Valdez Location Map

Valdez Coastal Management Plan December 1984

CONFIDENTIAL

Valdez Location Map

APPENDIX BB

Application to U.S. Department of Energy for Authorization to Export Liquefied Natural Gas

Category: Anderson Bay EIS-1995
YPC-ID#: 5.21.1
Word #1: DOE/ERA
Word #2: Export license
Word #3: Export application

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
BEFORE THE
ECONOMIC REGULATORY ADMINISTRATION

In the Matter of)
)
YUKON PACIFIC CORPORATION) ERA Docket No. 87-68-NG

APPLICATION OF YUKON PACIFIC CORPORATION FOR AUTHORIZATION TO EXPORT LIQUEFIED NATURAL GAS FROM THE UNITED STATES

Robert W. Perdue
Patrick C. Rock
Reynolds Shannon Miller Blinn
White & Cook
1667 K Street, N.W., Suite 300
Washington, D.C. 20006
(202) 293-7777

Jeffrey B. Lowenfels
General Counsel
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December 3, 1987

Marian Izzo

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UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
BEFORE THE
ECONOMIC REGULATORY ADMINISTRATION

Yukon Pacific Corporation) ERA Docket No.

APPLICATION OF YUKON PACIFIC CORPORATION
FOR AUTHORIZATION TO EXPORT LIQUEFIED NATURAL GAS
FROM THE UNITED STATES

Pursuant to Section 3 of the Natural Gas Act, 1/ Department of Energy Delegation Order No. 0204-111, 2/ and the administrative procedures of the Economic Regulatory Administration (ERA), 3/ Yukon Pacific Corporation (Yukon Pacific) hereby makes application for authority to export up to fourteen million metric tons of liquefied natural gas (LNG) annually from Port Valdez, Anderson Bay, Alaska, to the "Pacific Rim" countries of Japan, The Republic of Korea, and The Republic of China (Taiwan). The export authority sought herein is for a term of twenty-five years. The rationale for this Application and the facts supporting it are more fully described herein:

1/ 15 U.S.C. § 717b (1982).

2/ 49 Fed. Reg. 6684 (effective February 23, 1984).

3/ 10 C.F.R. §§ 590.201, et seq. (1987).

I.

THE APPLICANT

The exact legal name of applicant is Yukon Pacific Corporation. Yukon Pacific is an investor-owned corporation, organized and existing under the laws of the State of Alaska, with its principal place of business in Anchorage, Alaska.

Yukon Pacific was formed primarily to construct, operate, and maintain the Trans-Alaska Gas System (TAGS) and to market in selected Pacific Rim countries natural gas transported through TAGS. Currently, no facilities exist in the State of Alaska to transport Alaskan North Slope natural gas to any market, either domestic or foreign.

II.

COMMUNICATIONS AND CORRESPONDENCE

Any and all communications relating to any matter contained in this Application should be addressed to the following persons:

Robert W. Perdue, Esquire
Patrick C. Rock, Esquire
Reynolds Shannon Miller Blinn
White & Cook
1667 K Street, N.W., Suite 300
Washington, DC 20006
(202) 293-7777

Jeffrey B. Lowenfels, Esquire
General Counsel
Yukon Pacific Corporation
P.O. Box 101700
Anchorage, Alaska 99501
(907) 279-1596

III.

THE PROJECT

The TAGS Project includes the construction of a wholly-intrastate, 796.5-mile, 36-inch outside diameter, buried, and chilled natural gas pipeline, originating at Prudhoe Bay, Alaska, and terminating at a tidewater site on Port Valdez, Anderson Bay, Alaska. The pipeline is designed to transport up to 2.3 billion cubic feet (Bcf) of natural gas per day. The TAGS Project also contemplates (i) an LNG plant designed to remove any impurities from incoming gas, and to reduce the temperature of such gas to -259° F, thereby condensing it to a liquid state for storage and shipping; (ii) four LNG storage tanks, each with an individual capacity of 800,000 barrels (bbls); (iii) a marine terminal designed to berth and load two LNG tankers; and (iv) 15 LNG ocean transport vessels having individual cargo capacities of a nominal 125,000 cubic meters. Natural gas production wells and gathering systems are already in place to produce and gather the gas from the North Slope reservoirs.

Natural gas for the project will be delivered to the origin of the TAGS pipeline facility at Prudhoe Bay following a conditioning of the gas at either an existing or newly authorized gas conditioning facility (GCF). Ownership of the GCF will be determined through negotiations with those North Slope producers who will be contractually responsible for delivering an average of 2.3 Bcf per day of pipeline quality natural gas to Yukon

Pacific. Approximately 0.2 Bcf per day of natural gas will be utilized as fuel gas for compressor station operations along the pipeline route, and for operation of the facilities at the LNG plant.

The TAGS pipeline has been designed as a single, welded steel pipeline capable of transporting 2.3 Bcf per day of conditioned natural gas at a maximum operating pressure of 2220 pounds per square inch gauge (psig). Metallurgical specifications have been designed to accommodate the extreme range of temperatures that will be encountered over the life of the TAGS Project. The wall thicknesses for the different specified pipe grades will depend on location and anticipated loads. [4/] With the exception of selected river and fault crossings where below ground placement is not feasible, the pipeline will be buried with special consideration given to land areas where soil conditions favor long-term operation.

The alignment for the 796.5 mile pipeline begins at Prudhoe Bay, immediately downstream from the GCF, and proceeds south, generally within the utility corridor of the Trans-Alaska Pipeline System (TAPS). The joining of the pipe segments for the pipeline will be accomplished with welding methods that have been qualified for Arctic use in accordance with standards developed by the American Petroleum Institute and the American Society of

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4/ See 49 C.F.R. § 192.5 (1987).

Mechanical Engineers. 5/ Testing of the welds will be accomplished, in part, by a nondestructive x-ray process. 6/ The pipeline will have cathodic protection facilities and test stations for measuring pipeline electrical potential at regular intervals along the pipeline route. In addition, for safety purposes, emergency shut-off valves will be located along the entire route.

The sponsors of the TAGS Project are proposing the construction of ten mainline compressor stations to be located along the pipeline route in order to maintain adequate pressure for the transportation of the conditioned natural gas. Approximately 14 to 40 acres of land area will be required for the construction of each compressor station. Each station has been selected to satisfy engineering and environmental concerns, utilizing hydraulic studies as well as environmental review to determine optimal station location. Each site will contain a single 20,000 horsepower, turbine-driven mainline centrifugal compressor, and turbine-driven refrigeration equipment for cooling the gas. Chilling the natural gas not only enables the ground through which the pipe will run to remain frozen but will increase the capacity of the pipeline. Pipeline gas will be utilized as fuel for running both the gas compressors and

5/ These standards are referenced in 49 C.F.R. § 192.225 (1987).

6/ 49 C.F.R. § 192.243 (1987).

refrigeration equipment. Refrigeration will be accomplished by compressing, condensing, and circulating an external refrigerant to chill mainline gas flowing through heat exchangers. Each compressor station will be provided with emergency shutdown systems and station blow down valves to isolate the station and piping from the mainline and re-route the gas if necessary. Each compressor station will include on site utility systems for air supply, water supply, fuel storage, effluent treatment, electric power, glycol heating, maintenance facilities, a heliport, communication facilities, and living quarters for operations personnel.

An LNG plant will be located at the terminus of the pipeline at Anderson Bay, along the southern shoreline of Port Valdez, Alaska. Conditioned natural gas flowing from the pipeline will be treated, liquefied, stored in cryogenic tanks, and loaded onto tankers at the proposed marine terminal for export. The plant site consists of approximately 300 acres of land area immediately adjacent to the proposed marine terminal site described below. Critical facilities will be located on bedrock foundations, well above the highest historic water level. The facility is safely located over five miles from the City of Valdez - the closest population center to Anderson Bay. The facilities at the LNG site include metering facilities, four LNG processing trains, four 800-barrel cryogenic storage tanks, and LNG loading lines for two tanker berths.

Conditioned pipeline natural gas will enter the LNG plant where any moisture and impurities will be removed by passing the gas through a series of dryers and scrubbers. Thereafter, the gas will proceed through the liquefaction process.

Each liquefaction train will be air cooled and will operate in a parallel configuration. LNG produced in the trains will be transferred to special above-ground cryogenic storage tanks with a proposed total tank volume of 3,200,000 barrels or approximately five days of LNG storage at design production rates. The above ground tanks will be comprised of double wall construction with insulation and suspended roofs. They will consist of a nickel alloy steel, or an aluminum alloy inner tank with a carbon steel outershell in order to store the LNG at -259° F. The tank foundation will be electrically heated to prevent frost accumulation and will be surrounded by an impoundment system to contain any accidentally spilled LNG.

An LNG loading system has been designed with transfer piping sized for the system to load two tankers simultaneously within a 12-hour period. Plant utility systems include storage and distribution systems for fuel gas and diesel fuel, a generation and distribution system for electric power, storage systems for refrigerants, an air and nitrogen supply system and a plant effluent treating system.

The TAGS Project marine terminal facilities will consist of two LNG tanker berths, a cargo vessel berth, a ferry landing for site access, a tug and workboat pier, and a temporary construction off-loading dock. The two LNG tanker berths will be capable of mooring and loading LNG tankers with individual capacities ranging from 125,000 to 165,000 cubic meters. Each berth will consist of a loading platform and berthing and mooring dolphins. The LNG loading platform will be connected to the shore by a causeway, built on piles, carrying roadway, and piping. Loading operations at each berth will involve the use of articulated loading arms between the fixed platform facility and the floating vessel. Currently, four loading arms have been sized at 16-inch diameters to accommodate assumed loading rates. A single vapor-return arm will also serve to connect the tanker boil off with onshore vapor recovery facilities. Vapors will be returned to the plant fuel gas system or the feed gas stream for reliquefaction. Each loading arm will have an automatic shut-off valve to prevent LNG spillage during emergency conditions which will be in addition to the main LNG loading line automatic shut-off valve.

The TAGS Project also contemplates the use of fifteen LNG ocean transport vessels. Project sponsors are contemplating either direct ownership of the vessels by Yukon Pacific or contract operation of such vessels with a private carrier.

IV.

PROJECT FEASIBILITY

On November 11, 1983, a Joint Policy Statement was issued by Japan's Prime Minister and President Reagan calling for an increase in energy trade between the two countries, particularly an increase in the development of Alaskan resources. 7/ The two countries agreed to institute several significant initiatives in an attempt to reach their joint goal, including an effort to:

> ...encourage private industry in both countries to undertake now the pre-feasibility or feasibility studies necessary to determine the extent to which Alaskan natural gas can be jointly developed by U.S. and Japanese interests.

A pre-feasibility study was thereafter undertaken by Atlantic Richfield Company, serving as the U.S. sponsor group representative, and the Committee for Energy Policy Promotion, serving as the Japan sponsor group representative, to determine the feasibility of an LNG export project for gas produced from the North Slope of Alaska. The May 1987 Study, entitled "Alaska/Asian Gas System (AAGS) Pre-feasibility Study" (the "AAGS Study"), 8/ is segmented into three areas of study: The Alaskan North Slope Reserve Study, the Delivery System Study, and the

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7/ President Reagan and Prime Minister Nakasone,"Joint Policy Statement on Japan-U.S. Energy Cooperation" (November 11, 1983). The Joint Policy Statement is attached hereto as Exhibit D.

8/ The AAGS Study is attached hereto as Exhibit E.

Japan LNG Market Study. The AAGS Study found, among other things, that a North Slope LNG export project to Japan is feasible if markets outside of Japan are secured to satisfy the project's large scale capacity. The AAGS Project conceptualized by the AAGS Study is prototypical of the TAGS Project.

In June of this year, the Chicago-based Institute of Gas Technology (IGT) issued its "Evaluation of the Feasibility of Exporting North Slope Alaska Gas as LNG" (the "Study"). 9/ The Study addresses the important issue of whether the TAGS Project requires markets in addition to Japan in order for the export to be considered economically feasible. The Study indicates that with start-up deliveries at seven million tons per annum (50 percent of full project capacity), the TAGS Project is feasible and initial deliveries may commence as early as 1993 or 1994. In addition, estimates of initial project costs may be reduced from $11 billion to $8 billion. The most significant finding of the Study, however, is that the Japanese market alone could support the desired seven million ton start-up commitment.

According to the Study, the phased addition of the Korean market alone will significantly increase the ability of Yukon Pacific to market the entire 14 million ton annual capacity of the TAGS Project. Thus, the ability or inability of the TAGS

9/ The Study is attached hereto as Exhibit F.

sponsors to secure commitments for either the Taiwanese or Korean markets will not prove to be dispositive of TAGS' viability.

V.

EXPORT SOURCES

Since 1968, when oil and gas was discovered on the North Slope, a proven abundance of surplus natural gas reserves has laid dormant because no facility exists to deliver the gas to market. The historical development of natural gas production in the Texas-Oklahoma Panhandle Area, the Permian Basin-Delaware Basin Area, and Texas and Louisiana Gulf Coast Areas, starting in the 1940's, decisively illustrates that once surplus gas is committed to a market and begins to flow, additional exploration and drilling proliferates. This no doubt will be the pattern on the North Slope of Alaska, assuming that the economic incentives are present.

All gas being produced on the North Slope is associated gas, i.e., gas produced in conjunction with oil, and is either reinjected or used for fuel in the field operations, including fuel for compressors used in the reinjection process. It is estimated that utilization of the gas for such field operations results in an approximate 13 percent reduction in recovered reserves. 10/ Unless and until a system is built to remove the gas, this consumption will undoubtedly continue.

Yukon Pacific has entered into discussions with certain North Slope producers and the State of Alaska for the purchase and commitment of sufficient natural gas reserves to supply the long-term export contemplated by this Application. Yukon Pacific is assessing its options for the purchase of proven and current production from the Endicott, Kuparuk, Lisburne, Milne Point, Prudhoe Bay, and Thompson/Flaxman Island, North Slope production fields. 11/ These fields represent proven and producible reserves of approximately 36.6 trillion cubic feet (Tcf). Yukon Pacific anticipates that undefined or nonproducing fields in the North Slope will be developed and exploited by North Slope

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10/ See General Accounting Office, "Issues Facing the Future Use of Alaskan North Slope Natural Gas" Report RCED-83-102, at page 92 (May 12, 1982) (The "GAO Report"). The GAO Report concludes that:

> Over the next 25 years, field activities can be anticipated to consume a total of about 12.5 percent (3.3 Tcf) of the 26 Tcf of recoverable reserves in the Prudhoe Bay field before export. Delay of a transportation system beyond 1989 would increase the fuel consumed because of the continued need to fuel compressors for reinjection.

Id. at p. 92. The GAO Report goes on to state that prolonged reinjection may severely compromise oil recovery from Prudhoe Bay and gas may therefore eventually have to be flared.

11/ Exhibit G hereto is a chart depicting these fields by gas reserves, operator, gross production, volumes injected, and volumes used and sold.

producers once the TAGS pipeline facilities have been constructed. These undefined or nonproducing fields include Beechy Point, Coleville Delta, East Umiat, Gwyder Bay, Harvard, Hemi-Springs, Kaktovik, Kavik, Kemik, Niakuk, North Star, Reservoir, Seal, Tern, Umiat, and West Sak. 12/ This vast supply may also be utilized to serve the market and needs of the Alaskan Natural Gas Transportation System (ANGTS) should that system ever be completed.

Yukon Pacific's supply procurement efforts will focus primarily on purchasing natural gas produced from the Prudhoe Bay oil field and, in particular, the gas cap from Prudhoe Bay's main oil producing formation -- the Sadlerochit formation. Consideration will be given to any surplus gas from the Kuparuk field and the Endicott field as well as natural gas from Thompson/Flaxman Island.

In January of 1987, the Alaska Department of Natural Resources issued its study and report entitled "Historical and Projected Oil and Gas Consumption" wherein it concludes that the current estimate of North Slope recoverable natural gas reserves is 37.0 Tcf. This comports with a 1986 federal study by the United States Minerals Management Service (MMS) which concluded that there are 36.5 Tcf of known gas resources in the Prudhoe Bay

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12/ Exhibit H hereto is a chart depicting these fields by lease (state or federal), operator, 1986 production status, and relevant comments.

Area. Estimates of undiscovered recoverable North Slope gas resources were recently revised to indicate a minimum recovery of 23 Tcf, a most likely recovery of 97 Tcf, and a maximum recovery of 304 Tcf. 13/ These estimates do not include the onshore prospects of Alaska's Arctic National Wildlife Refuge (ANWR) which is estimated to contain undiscovered resources comparable to those contained in the Prudhoe Bay area of Alaska. The Bureau of Land Management (BLM) estimated in 1985 that the ANWR has in place natural gas reserves of approximately 31.3 Tcf. 14/

Unlike North Slope oil reserves, the export of which is specifically precluded by statute, 15/ there is no law that explicitly prohibits the export of North Slope natural gas. Indeed, there are laws that explicitly provide for its export. Specifically, Section 12 of the Alaskan Natural Gas

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13/ Potential Gas Committee, Potential Gas Agency, Colorado School of Mines "Potential Supply of Natural Gas in the United States", (December 31, 1986) at p. 119 (issued April, 1987).

14/ <u>See</u>, Cooke, Larry W., "Estimates of Undiscovered Economically Recoverable Oil and Gas Resources for the Outer Continental Shelf as of July 1984: U.S. Department of the Interior, Minerals Management Service," Offshore Resource Evaluation Division, OCS Report MMS 85-0012 (1985) at p. 45. <u>Compare</u> Dolton, G. L. and others, "Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States: U.S. Geological Survey Circular 860," (1981) at p. 87, wherein future discoveries of federal offshore natural gas are estimated to be 64.6 Tcf.

15/ <u>See</u> 50 U.S.C. § 2406(d) (1982).

Transportation Act (ANGTA) [16/] provides that exports of North Slope gas are subject to the Natural Gas Act and the Energy Policy Conservation Act, as well as to the requirements contained in Section 12 of ANGTA itself. [17/] Each of these statutes makes provision for exports of North Slope natural gas. So long as these statutes are satisfied, North Slope natural gas may be exported.

There are no North Slope natural gas reserves that have been "dedicated" to interstate commerce under the provisions of Section 7 of the Natural Gas Act. Although the Federal Energy Regulatory Commission (FERC), the courts, and the natural gas industry commonly refer to gas as being "dedicated to interstate commerce," there is no mention in Section 7 of the Natural Gas Act of "dedication." Rather, Section 7 speaks in terms of obtaining certificates and authorizing service. However, because under the statute a service obligation attaches as a matter of

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16/ 15 U.S.C. § 719j (1982).

17/ Part 1 of House Report No. 94-1658, issued on ANGTA by the House Committee on Interstate and Foreign Commerce, includes a letter from former Federal Energy Administrator Frank G. Zarb to Congressman Staggers which states, in pertinent part, that:

> Section 12 [of ANGTA] which limits exports of Alaska natural gas to any nation other than Canada or Mexico <u>is unnecessary</u> since the Energy Policy and Conservation Act already requires export controls on natural gas.

H.R. Rep. No. 1658, 94 Cong., 2d Sess., Part 1 at 38 (1976) (emphasis added).

law to natural gas which is sold in interstate commerce for resale, natural gas which is so sold is said to be "dedicated to interstate commerce." As stated by the Supreme Court:

> Section 7(e) vests in the Commission control over conditions under which gas may be initially dedicated to interstate use. Moreover, once so dedicated, there can be no withdrawal of that supply from continued interstate movement without Commission approval. 18/

In the usual situation, under the Natural Gas Act a producer dedicates natural gas by executing a contract for the sale of gas from certain acreage, applying for and receiving a certificate authorizing sales under that contract, and actually commencing sales from that acreage pursuant to the contract and certificate. At the time the ANGTA was enacted, commencement of the sale and delivery of North Slope natural gas to the ANGTS would have "dedicated" certain gas reserves to interstate commerce under the Natural Gas Act. Such sales arrangements could not thereafter be abandoned without the FERC's authorization. However, no such sales or deliveries have occurred and no dedication has thereby attached to any North Slope natural gas reserves. 19/

18/ Atlantic Refining Co. v. Public Service Commission of New York, 360 U.S. 378, 389 (1959).

19/ In 1979, gas purchase contracts were executed by a number of natural gas transmission companies with Prudhoe Bay producers for gas reserves located in the Sadlerochit Formation of the Prudhoe Bay Field. The major producers (cont)

ANGTA represents the legal means by which a pipeline system, i.e., ANGTS, is granted the exclusive right to transport North Slope natural gas to the Lower 48 states. In other words, in the event that natural gas is to be delivered to the Lower 48 states, it may only be accomplished through ANGTS. This is quite apart from restricting the destiny of North Slope natural gas. Had ANGTA precluded selling North Slope gas reserves elsewhere, it would have effected a taking of property, requiring compensation in accordance with the mandates of the United States Constitution. 20/ Moreover, Section 12 of ANGTA, which requires a Presidential finding before exports of North Slope natural gas may take place, by its mere existence, represents a recognition that the export of North Slope natural gas is possible and, moreover, may pose a net economic benefit to the country as a

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divided their commitments among several purchasers. These contracts typically (if not consistently) provided that if the purchaser did not receive all necessary certificates, permits, and authorizations by March 1, 1982, then:

> ...seller shall thereafter have the right and option, to be exercised at any time, to terminate [the] agreement by giving notice of termination to buyer. If buyer fails to obtain the required authorization by such date, or rejects same upon issuance thereof, then either party may terminate [the] agreement by giving notice to the other party and neither party shall be liable thereafter.

A number of contracts have, by operation of this provision, since been terminated.

20/ See, for example, Aleut Corp. v. Arctic Slope Regional Corp., 484 F. Supp. 482, 485, n. 6 (D. Alaska 1980) and Pennsylvania Coal Co. v. Mahon, 260 U.S. 393 (1922).

whole. ANGTA further represents a recognition that the natural gas reserves located on the North Slope may be sufficient to support (i) an export project such as the TAGS Project, which offers a number of benefits to the United States via the international marketplace, and (ii) a domestic project, such as the ANGTS, which was envisioned to deliver secure supplies to the Lower 48 states during the domestic natural gas shortage of the 1970's. In other words, the Congress has recognized that these two scenarios are not mutually exclusive.

VI.

EXPORT MARKETS

In Asia, broad scale LNG use has begun relatively recently, but continues to grow quickly. Natural gas from the TAGS Project is to be marketed in Japan, South Korea and Taiwan. These three Pacific Rim countries depend on imported energy for at least 75 percent of their needs. Each has established a reduced dependence on crude oil as its national objective. From the United States' perspective, all three nations maintain trade surpluses which could be offset to a significant degree by LNG purchases realized through the TAGS Project. A major sale of Alaskan LNG would be the largest single United States' export serving to reduce these deficits.

To ensure diversity and adequate marketing prospects, Yukon Pacific proposes to market LNG to all three nations. However, need for the TAGS Project is demonstrated in Japan alone, where projected increases in total demand for energy in the year 2000 are more than five times that provided by the TAGS Project.

Japan

The infrastructure for the importation of LNG into Japan is already in place, but may need to be expanded. Today, there are ten LNG import terminals located near the major population and industrial centers of Tokyo, Osaka, Nagoya, Niigata and Kita Kyushu, and three new import terminals are under construction. The distribution systems in Tokyo and Osaka obtain more than 75 percent of their city gas supply from imported LNG.

During the 1960's, 80 percent of Japan's primary source of energy was petroleum, the large majority of which came from the Middle East. By 1985, Japan's dependency on petroleum was reduced to 57 percent, and there is a national objective to further reduce the dependency on petroleum to about 42 percent by the turn of the century. LNG was introduced into Japan in 1969, through importation from the Kenai, Alaska project. 21/ By 1984, LNG use had increased to approximately ten percent of Japan's primary energy requirements. Today, there are 110 LNG storage tanks in operation in Japan with a total capacity of 7.765 million kiloliters, or approximately 50 million barrels. At full

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21/ See Phillips Petroleum Co. and Marathon Oil Co., 37 FPC 777 (1967), amended 1 ERA (CCH) ¶ 70,116 (1982).

capacity, approximately 600,000 barrels of LNG per day (14 million tons per year) will be produced by the TAGS Project.

Japan is currently using an estimated 28 million tons of LNG per annum, with 75 percent going to electric power generation and 25 percent into city gas distribution systems. The Japanese Ministry of International Trade projects this use to reach 40 million tons per annum by 1995. Until recently, Japan has made little effort to penetrate the industrial gas market. 22/

In fiscal year 1984, 44 percent of the total electrical output from all thermal power stations was generated with 21 million tons of LNG, while 56 percent of all city gas was supplied by five million tons of LNG. Further, Japan has been a world leader in utilization of the "cold" emitted by LNG, with extensive use in liquefaction and separation of air, liquefaction of carbon dioxide, refrigeration for super frozen foods, and cryogenic power generation.

Consumption of city gas per customer in Japan is quite low as compared to the United States. The Japanese residential customer uses approximately one-seventh as much as the average United States' customer. Likewise, the Japanese commercial customer uses about one-eighth as much as the United States' commercial customer, and industrial customers only one twenty-eighth the amount of United States' industrial customers.

22/ In 1984, only 1.4 percent of Japan's industrial market was supplied by natural gas.

Because of the smaller homes, shops and industries, Japanese per customer energy consumption will probably never reach the level of the United States' customer; however, there is great potential for overall increase as the homes and shops become larger with the increasing affluence of the Japanese.

The delivered cost of city gas to the residential customer in Japan is approximately three times the average cost in the United States. This relatively high price has an influence on the amount of city gas sold in the competitive commercial and industrial markets. The local gas distribution companies are recognizing the potential for increased sales in the commercial and industrial sector and are structuring their rate schedules in order to increase their share in these competitive markets.

Japan receives over 85 percent of its LNG supply from Southeast Asia; of this, approximately 50 percent comes from Indonesia. Japan, however, recognizes the necessity of diversified sources of energy -- especially since the Middle East "oil shocks" in 1973 and 1979. In recent business and energy publications, the TAGS Project has been recognized as one of the attainable projects available to serve Japanese markets. 23/

23/ See, for example, Minard, "Gas for the Lamps of Seoul?" Forbes, March 23, 1987 at 34; Oil & Gas Journal, "IGT: Phasing Could Make TAGS Viable," August 17, 1987 at 26; Foster Natural Gas Report, "Yukon Pacific Considering Results of New Study Showing Lower Costs and Greater Marketability for TAGS Project," August 13, 1987 at 29; and (cont)

Republic of Korea

Korea Gas Corporation (KGC), a wholly-owned government corporation, was established in August 1983 under the Korea Gas Corporation Act promulgated in December 1982. The prime aim of this corporation is to "promote improvement of the South Korean national lifestyle and to contribute to the rising standard of public welfare by establishing the foundation for supplying a pollution-free and safe gas on a stable and long-term basis."

KGC has completed its LNG import terminal at Pyong-Taek, south of Inchon. LNG was initially imported from Indonesia into South Korea in October 1986. Future plans call for a second LNG terminal to be located in the Pusan area.

The capital city of Seoul, which is now served by seven privately owned city gas distribution companies, commenced receiving LNG in February of 1987. A 100 km transmission line and a main distribution line (112 km) which rings the city is essentially in place. The second phase of the KGC plan will supply eight cities in central South Korea. Long-range plans call for building a gas grid to supply the entire country with LNG for residential, commercial, and industrial markets. These projects are based on a feasibility study completed by KGC in early 1986.

Oil & Gas Journal, "LNG Shipments to Orient Seen Best Outlet for North Slope Gas," September 9, 1985 at 76.

South Korean planners have recognized the large potential for gas in the commercial and industrial sectors and have adopted diversified gas use as a national policy. Unlike Japan, it is expected that development of the South Korea gas system will include large segments of commercial and industrial gas sales. This is similar to the pattern used by the British Gas Corporation upon the introduction of natural gas into its gas system which increased its sales by a factor of four over the relatively short period of five years.

For example, Seoul, which has a population of approximately ten million, now has 330,000 households served by the present seven private city gas distribution systems. It is expected that by 1991 there will be 920,000 additional households eligible for connection to the city gas systems.

South Korea is experiencing a severe shortage of soft coal which constitutes the main source of residential fuel, but also is a major contributor to a very serious air pollution problem. The volume of LNG used is expected to reach two million metric tons per annum by 1988, primarily for electric power generation by Korea Electric Power Company (KEPCO). KEPCO plans to adjust its LNG use as the market for city gas customers increases. Industrial development is moving quite rapidly, and it appears that South Korea's economy is growing as the Japanese economy did in the 1960's and 1970's.

KGC has an aggressive and ambitious program to serve the entire nation with natural gas. Some estimates suggest South Korea will more than double its consumption of gas by 1995, and quadruple it by the year 2000.

Mr. H. B. Sunwoo, Vice-President of KGC, presented a paper in November of 1986 which provided a forecast of Korea's LNG supply and demand. 24/ The paper projected that beginning in 1996 an additional one million tons per year would be imported to KGC's existing LNG receiving terminal at Pyeong Taek near Inchon and, in that same year, an additional two million tons of LNG would be imported into a new terminal to be built to serve Southeast Korea. Total Korean imports would, therefore, be increased by three million tons per year beginning in 1996. 25/

Republic of China (Taiwan)

Chinese Petroleum Corporation, a wholly owned government corporation, is responsible for oil and gas in Taiwan. It is the purchaser of LNG from Indonesia and is responsible for the LNG terminal and the natural gas transmission system. Taiwan has a

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24/ Sunwoo, H.B., Korea Plans for LNG Imports, at pp. 66-67, presented at GASTECH 86 LNG/LPG Conference, Hamburg, Germany on November 25-28, 1986 (Herts, England: GASTECH LTD, 1987).

25/ *See* Exhibit F (IGT Study) at p. 15.

natural gas distribution system in the Taipei area that handles about 100 million cubic feet per day of local production. Taiwan has agreed to purchase 1.5 million metric tons of LNG per annum from Indonesia commencing about 1991. An LNG import terminal is under construction at Hsingta on the southwest shore of Taiwan. It will be connected to the present gas distribution system near Taipei by a 200-mile gas transmission system, giving gas service to the major population areas of western Taiwan.

Taiwan has used its indigenous natural gas supplies for residential, commercial and industrial markets; however, with the decline in local gas supplies, the industrial markets have been forced to seek other fuels. With a gas system in place by 1991, Taiwan will be in a position to capitalize on these markets once LNG is available and will be able to expand its needs for additional supplies of natural gas. Taiwan is a potential market for some additional two million metric tons per annum of LNG.

VII.

CONTRACT TERMS

As noted above, natural gas transported through the TAGS pipeline will be purchased by Yukon Pacific from North Slope producers. After transport through TAGS and conversion into LNG, the LNG will be exported and sold to customers in the Pacific Rim. The associated purchase and sale agreements of such LNG will be executed by and between Yukon Pacific, on its own behalf, as seller, and Pacific Rim purchasers, as buyers, including, but not limited to, local distribution companies, electric utility companies and industrial end-users. The exports will be for Yukon Pacific's own account.

Yukon Pacific has entered into discussions with various parties in Japan, South Korea, and Taiwan interested in importing LNG exported from Alaska through the TAGS facilities. The nature and magnitude of the TAGS Project dictate that the gas purchase agreements with the Pacific Rim purchasers be long-term in nature. The contract terms, therefore, shall be 25 years in duration, commensurate with the term of export authorization sought herein. Individual or joint signatory contracts will be designated by the buyers.

Export volumes of LNG will total up to 14 million metric tons annually; however, to accommodate flexibility in the market demand, the volume of LNG sold and delivered each year may be near or below the contract volume in any given year. Specific volume breakdowns by Pacific Rim purchaser are not determinable at this time, but will be submitted to the ERA as soon as they become available. 26/ Transportation of the LNG to the Pacific Rim destinations will be the responsibility of Yukon Pacific and will be accomplished by LNG ocean transport vessels. Transfer of title will be outside U.S. territorial waters. Delivery terms

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26/ At full project capacity of 14 million tons per year, estimated volume breakdowns for LNG exports to the Pacific Rim countries are as follows: Japan = 7 million tons, Korea = 5 million tons, and Taiwan = 2 million tons.

will be the customary ex-ship place of destination -- or, if the purchaser is supplying the ship, such terms will be FOB. 27/

The purchase price for natural gas on the North Slope will be determined using a base price per million British thermal units (MMBtu) tied to the LNG sales price ex-ship Pacific Rim destination. The price for the initial sale of gas in the field will be adjusted in accordance with the following mechanism:

> (1) If the price of the LNG sold ex-ship Pacific Rim destination is <u>more than</u> the negotiated base price/MMBtu, then the price paid by Yukon Pacific to the North Slope seller shall be adjusted <u>upward</u> by a negotiated percentage of any such difference, or
>
> (2) If the price of the LNG sold ex-ship Pacific Rim destination is <u>less than</u> the negotiated base price/MMBtu, then the price paid by Yukon Pacific to the North Slope seller shall be adjusted <u>downward</u> by a negotiated percentage of any such difference.

In no event, however, will such price be adjusted to exceed the Natural Gas Policy Act § 109 Ceiling Price. 28/

The specific terms peculiar to each producer agreement will be determined between the parties through arms'-length negotiations and will, therefore, be necessarily responsive to

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27/ The phrase "ex-ship Pacific Rim destination" indicates that the price quoted applies at the point of destination, *e.g.*., Tokyo Harbor. The term "FOB" or "Free on Board" commonly indicates that the buyer will assume the burden and costs of transporting the exported goods from an agreed upon point in the exporting country.

28/ 15 U.S.C. § 3319 (1982).

market conditions and will reflect what a willing buyer is willing to pay a willing seller. Due to the duration of the commitment, the contract terms will be flexible by providing for variations in market requirements and by providing make-up periods for gas not taken. Natural gas takes will likely be based on Yukon Pacific's total market requirements and will be apportioned among the various producers on the basis of their proportionate share of the aggregate producer commitment to the TAGS Project. The major producers in the North Slope are Atlantic Richfield Company (ARCO), Exxon Company, U.S.A., and Standard Alaska Production Company (British Petroleum) who together own over 90% of the reserves. Mobil Oil Company, Chevron U.S.A., and Phillips Petroleum Company own lesser interests. The State of Alaska owns a 12.5% royalty share.

The price term of the Pacific Rim gas purchase agreements for LNG delivered will consist of a base price per MMBtu, as indexed in accordance with the following formula:

Price for each calendar month =

$$A \text{ (U.S. cents) } X \; \frac{\text{Average Crude Oil Price for Month Prior to the Calendar Month}}{B}$$

Where:

A = Base price for the LNG per MMbtu
B = Crude oil price

The relationship of A to B will be determined through arms'-length negotiation. The average crude oil price is the average of the government selling prices (GSP) in U.S. dollars per barrel for selected major crude oils imported into Japan. 29/

If at any time any of the GSP's used in the pricing formula ceases to be published, or is quoted on a revised basis, Yukon Pacific and the buyer shall promptly meet to agree on an appropriate modification. If for a period of at least ninety (90) days the GSP, at any time during such period, for any one or more crude oils is, in the judgment of either party, not in reasonable agreement with the actual selling price of such crude or crudes, then either party may request a revision thereof. If the parties fail to agree on a revision, then a revision will be made by an arbitrator in accordance with the contract's arbitration clause.

Like the contracts to be negotiated between Yukon Pacific and various North Slope producers, the specific terms of each LNG sales agreement between Yukon Pacific and Pacific Rim purchasers will be determined between the parties through arms'-length negotiations and will, therefore, be necessarily responsive to international natural gas market conditions and reflect what a willing buyer is willing to pay a willing seller. Generally, the contracts will contain industry standard provisions for measurement, payment, force majeure, gas quality,

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29/ For purchases in South Korea and Taiwan, the crude oil prices to be used in the pricing formula will be determined through arms'-length negotiations.

notices, warranty of title, arbitration, remedies for default, and government approvals. An executed copy of each LNG sales contract with Pacific Rim purchasers will be supplied to ERA as soon as they become available.

VIII.

PUBLIC INTEREST

Consistent with Section 3 of the Natural Gas Act, Department of Energy Delegation Order No. 0204-111, and ERA precedent, an application to export natural gas must be approved unless it is determined that the export is not consistent with the public interest. 30/ The proposed long-term export will serve the public interest. The terms and conditions of the producer and Pacific Rim market gas purchase contracts will be flexible with respect to price and will contain volume provisions drafted to maintain steady exports, thus assuring a gas supply that can be marketed competitively over the 25-year life of the export authorization. These contract terms will also serve to generate an acceptable return for the investors in the TAGS Project.

In reviewing natural gas export applications in the past, the ERA has consistently and primarily considered the "lack

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30/ See, e.g., Yankee International Co., 1 ERA (CCH) ¶ 70,617 (1985).

of domestic need for the gas." 31/ As demonstrated below, no present or future domestic need exists for this gas.

A. National and Regional Need for North Slope Natural Gas

There currently exists a substantial natural gas supply surplus in the United States. 32/ The Federal Energy Regulatory Commission recognized this surplus in its Order No. 440, 33/ wherein it, inter alia, revoked an earlier statement of policy determining that a natural gas supply shortage existed in the United States. With respect to the need to take this action, the Commission's order forthrightly states:

> In numerous Commission dockets, gas companies and their customers have acknowledged the current excess of gas supply. The evidence before the Commission

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31/ See, e.g., Great Lakes Transmission Co., 1 ERA (CCH) ¶ 70,597 (1985), wherein the ERA noted that "the primary consideration bearing on exports is the lack of domestic need for the gas." Id. at p. 72, 405. The competitiveness of Yukon Pacific's export proposal is not at issue because the volumes are being sold to foreign rather than domestic consumers. The pricing provisions of the Pacific Rim sales contracts, however, will likely call for the LNG to be sold at a competitive price, thereby ensuring that these resources will go a long way in reducing the balance of payments with those Pacific Rim countries purchasing the LNG. See also Natgas (U.S.) Inc., 1 ERA (CCH) ¶ 70,668 (1986).

32/ See, Yankee International Co., 1 ERA (CCH) ¶ 70,641 at p. 72,523 (1986); DOE Policy Guidelines, 1 ERA (CCH) ¶ 70,011 at pp.. 70,011-012 (1984).

33/ FERC Stats. and Regs. [Regulations Preambles 1982-1985] ¶ 30,674 (1985).

clearly shows that the supply of natural gas is sufficient for the foreseeable future.

It is clear that there is a sufficient supply of natural gas to meet the current requirements and further that the supply is sufficient for the future. Therefore, the short supply determination in Order No. 448 is revoked. 34/

Since the passage of the Natural Gas Policy Act in 1978, it has become increasingly clear that domestic natural gas resources are plentiful. 35/ Yukon Pacific submits that this supply surplus will continue well beyond the year 2000, given current market conditions in the United States, and the plethora of accessed and accessible Canadian and Mexican natural gas reserves. Yukon Pacific has prepared Exhibit I hereto which is an exhaustive inventory and summary of domestic gas supply studies, analyses, and estimates performed by various industry groups and governmental agencies. With respect to the North Slope and the

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34/ FERC Stats. and Regs. [Regulations Preambles 1982-1985] ¶ 30,674 at p. 31,625, see, generally, FERC Stats. & Regs. [Regulations Preambles 1982-1985] ¶ 30,665 (1985) (Order No. 436).

35/ See, Testimony of George H. Lawrence, President, American Gas Association, Before the Subcommittee on Energy Regulation and Conservation, Committee on Energy and Natural Resources, United States Senate, July 11, 1985, at p. 5 where he emphasizes:

> "the dramatic improvement in natural gas supply since the NGPA was enacted. These supply improvements in response to the higher NGPA prices have demonstrated conclusively that the interstate market gas supply problems during the 1970's reflected the inadequacies of wellhead price controls rather than the limits of the domestic gas resource base".

ANWR, it evidences that, without exception, these reserve studies and estimates consider these reserves to be enormous.

Assuming, arguendo, that a domestic supply shortage were to emerge before the turn of the century, the feasibility of accessing the distant North Slope reserves that are contemplated for export by this Application must be seriously questioned. No infrastructure exists to bring these reserves to market in the Lower 48 states. Moreover, given the staggering $36 to $45 billion estimated cost to complete a system capable of delivering this gas to the Lower 48 states, 36/ were gas to become available, the price offered to the domestic consumer would be so high as to render the gas unavailable. Interestingly, as part of the Federal Energy Regulatory Commission's recent notice of proposed rulemaking on the abandonment of sales and purchases of natural gas, 37/ the

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36/ According to the October 22, 1981 testimony of John J. McMillian, then Chairman, Board of Partners of Alaskan Northwest Natural Gas Transportation Company, before the U.S. Senate, Committee on Energy and Natural Resources, the 1980 dollar estimate of total Alaska Natural Gas Transportation System (ANGTS) costs, with a built-in factor for contingencies, is $23 billion for a project with a completion date of 1986. Adjusted for inflation to 1986, "the resulting range of cash requirements to construct the total system is $28.7 billion to $47.6 billion. The pre-build phase is estimated to be completed for $2.4 to $2.7 billion. Therefore, the net required amount to finance the remaining ANGTS facilities is $36.3 to $44.9 billion." (See, p. 1016 of prepared testimony) (emphasis added).

37/ See, Notice of Proposed Rulemaking, "Abandonment of Sales and Purchases of Natural Gas Under Expired, Terminated, or Modified Contracts", Docket No. RM87-16-000 (issued May 7,
(cont)

Commission's Office of Pipeline and Producer Regulation conducted a study addressing dedicated and potential sources of gas supply [38] wherein North Slope gas reserves are conspicuously omitted in the study's factoring of future domestic supply sources. The Commission appears to agree that cost considerations effectively render this supply unavailable to domestic markets.

More recently, and perhaps more telling of the diminished viability of completing a system able to deliver competitively priced North Slope natural gas to the Lower 48 states, are the representations of Northern Border Pipeline Company (Northern Border) in its system expansion filing. On November 13, 1987, Northern Border filed an application with the FERC pursuant to Section 7(c) of the Natural Gas Act seeking authority to expand its system from Iowa into Illinois. Northern Border constitutes the eastern leg of the "pre-built" portion of ANGTS. With respect to its relationship to ANGTS, Northern Border states in its application that:

> Northern Border "pre-built" the eastern leg of the [ANGTS] to allow for the transportation of Canadian natural gas to U.S. markets. Subsequently, the requirements of the energy markets changed and the full development of ANGTS has been delayed indefinitely....
>
> * * *

1987).

38/ Id., at Appendix A, entitled "Dedicated Interstate Gas Supply, Potential Supplemental Supply Sources and Their Effects on Meeting Potential Demand".

While market forces and economics have delayed the need for the Alaskan natural gas reserves, ... [t]here exists within the Province of Alberta and Saskatchewan in Canada and the Williston Basin Region large natural gas reserves. These reserves are capable of meeting the long-term needs of the market and are available at competitive prices to the Midwest U.S. markets. 39/

Northern Border candidly concurs that Alaskan North Slope reserves are an unlikely future supply source for the Lower 48 states. Indeed, Northern Border depicts its system as one built for the delivery of "Canadian", not Alaskan, reserves.

Economically, these reserves are more valuable to the United States as an export than if consumed domestically. Staff members of the Federal Energy Regulatory Commission conducted a study in 1981 using an indexed financing schedule for the proposed ANGTS which projected that, depending upon the tariff methodology implemented, the price for ANGTS gas delivered to the Lower 48 states could range from a low of $8 per Mcf to a high of $21 per Mcf (1987 dollars). 40/ The average price for natural gas in this country has never approached $8 per Mcf, let alone $21 per Mcf. Today, non-conventional sources of gas, such as gasified coal, and imported sources of gas, such as Canadian and Algerian gas, are more economically attractive sources to meet United States' demand than North Slope gas. The costs associated

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39/ Northern Border Pipeline Company, Docket No. CP88-77-000, Application at p.9 (filed November 13, 1987) (emphasis added).

40/ See The GAO Report (Note 10, supra) at p.34.

with delivering North Slope gas is simply too high. On the other hand, exporting North Slope gas results in enormous economic benefits to the nation as a whole. The most apparent of these benefits is a reduction in the United States' trade deficit which is addressed later in this Application.

Therefore, Yukon Pacific respectfully urges that the Administrator give fair and due consideration to the possibility that, under the ANGTS proposal, natural gas from Alaska's North Slope may never be economically transported to domestic markets in the Lower 48 states.

Yukon Pacific does not mean to imply that a project designed to supplement United States' supplies is not feasible. At least one project, known as Polar Gas, was formed to accomplish the delivery of gas located in the Canadian Arctic Frontier to the Lower 48 states. The project, sponsored by Trans-Canada Pipelines, Panarctic Oils Ltd., Tenneco Energy Ltd., and Petro-Canada, contemplates the construction of a pipeline to connect vast Northern Canadian reserves to the "pre-built" portion of the ANGTS. In its February 10, 1987, presentation to the Canadian House of Commons' Standing Committee on Energy, Mines, and Resources, the Polar Gas Project sponsors demonstrated that the Beaufort Sea and Arctic Island reserves their project intends to develop contain between 70 ("high confidence") and 274 ("speculative") Tcf of recoverable natural gas resources.

Finally, the gas reserves contemplated for export by this Application are excess to those required for local Alaskan use. The state's demand for natural gas can easily be satisfied by a negligible percentage of the state's vast natural gas resource base. For example, the City of Anchorage, Alaska's major population center, is currently supplied with gas produced from Alaska's Cook Inlet Basin. Current estimates of Cook Inlet reserves are more than adequate to meet local demand far into the foreseeable future. 41/

B. Reduction in the United States' Trade Deficit

As Alaska LNG trade promotes cooperation in energy trade with our allies, it also serves to reduce the significant United States' trade deficit. Due to its unfavorable balance of payments position, United States national policy favors exports in general, and exports to the Pacific Rim countries in particular. The aggregate 1986 U.S. trade deficit with Japan,

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41/ According to the April 1987 Report of the Potential Gas Committee of the Potential Gas Agency, (See Note 13, supra.) maximum probable Cook Inlet reserves, both onshore and offshore, equal 2.4 Tcf. The annual demand for natural gas from this area, including those volumes extracted to satisfy the Phillips/Marathon Kenai export project, equals approximately 197 Bcf. Allowing for normal growth in demand and extraordinary factors that may affect demand, proven reserves in this area constitute at least a 20-year regional supply.

Korea, and Taiwan was approximately $78.3 billion. 42/ The United States' trade deficit with Japan stands at approximately $38 billion for the first three quarters of 1987. 43/ Alaskan LNG exports will, without a doubt, significantly reduce this trade deficit by generating upwards of $3 billion in annual sales, even assuming a low end delivered sales price of $4 per thousand cubic feet of natural gas.

Japanese Prime Minister Nakasone recently publicly committed Japan to a national goal of reducing its huge trade surplus with the United States by substantially increasing its purchases of United States' products. However, there has existed a trade tension between the United States and Japan because of the paucity of United States' exports demanded or needed in the Japanese market. Fortunately, Alaska's rich endowment of energy supplies, including natural gas, and Japan's concomitant lack of domestic energy resources, can serve to fill this void. Japan's LNG consumption is projected by the Japanese Ministry of International Trade and Industry to rise from 28 million tons

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42/ This figure may be broken down as follows:

Japan = $57.6 billion
Korea = $ 6.4 billion
Taiwan = $14.3 billion

Sources: Embassy of Japan and U.S. Department of Commerce.

43/ Japan Economic Institute, "Higher Yen Reins in Japan's Trade Surplus", JEI Report, Report No. 40B (October 23, 1987) at p.3.

annually in 1986 to between 38 and 46 million tons annually in 1990. Yukon Pacific's annual sales of between 10 and 14 million tons can easily satisfy a large portion of this demand and serve as the perfect commodity for improving trade.

C. Benefits to United States' Foreign Relations

Exports of LNG to Pacific Rim countries made possible by the TAGS Project will materially benefit and strengthen United States trade and political alliances with those nations. Early in 1983, the Reagan Administration, Alaska Governor William Sheffield, and the Alaska Legislature all endorsed the idea of locating Asian markets for the export of North Slope natural gas. Later that year, the late United States Commerce Secretary Malcolm Baldridge wrote:

> "[t]he Administration views the development of Alaska North Slope natural gas as a major contributor to western energy security. Whether the gas is marketed in the United States or abroad, it reduces demand for OPEC and Soviet energy and clearly results in significant benefits to the U.S. economy." 44/

The Department of Energy echoed that sentiment in its 1983 National Energy Policy Plan, wherein it stated:

> [A] principal concern of this Administration's international energy policy involves national security interests and the importance of

44/ As clear evidence that this sentiment continues, the 1987 Session of the Alaska State Legislature endorsed exports of Alaska gas to Pacific Rim markets. See, Senate Resolution No. 22.

> cooperative efforts to find secure and economic alternatives to increased western reliance on insecure and prospectively uneconomic Soviet supplies.

These declarations are particularly relevant to the present situation because Japan is exploring long-term contracts with the Soviet Union for natural gas produced in Soviet territory. Indeed, the Sakhalin Island Project is a Soviet-sponsored proposal predicated on sales of LNG to Japan some time in the 1990's.

Exports of North Slope LNG are also consistent with the mandate of the International Energy Agency, to which both the United States and Japan belong, which endeavors to protect its industrialized, non-communist member nations from disruptions in energy supplies. The agency seeks to promote the energy interdependence of the free world by encouraging our allies to diversify their energy sources, thus minimizing energy reliance on politically unstable regimes. Long-term United States' LNG exports to Japan will provide a substantial and stable portion of Japan's future natural gas needs, thus enhancing their energy security in the event of a supply disruption. LNG exports to Japan will also reduce the nation's economic reliance on non-allied nations.

Notably, at the end of 1983, when President Reagan and Japan's Prime Minister issued their Joint Policy Statement on energy cooperation, committing their countries to encourage private industries to develop energy resources and, specifically, to study jointly the feasibility of marketing Alaskan natural gas in Japan, they specifically found that:

> [T]aking account of the energy prospects for the entire Pacific Basin, the two countries agree that the sound expansion of U.S.-Japan energy trade will contribute to the further development of the close economic and energy security relationship which exists between the two countries . . . . Both countries consider Alaska to be a particularly promising area for joint development of energy resources. 45/

While Japan is clearly the largest available market for Alaskan LNG exports, Yukon Pacific also intends to market gas to Taiwan and Korea. In a letter to Mr. Walter J. Hickel, Chairman of Yukon Pacific, the Republic of China's Minister of Economic Affairs, Y. T. Chao, wrote:

> As part of our plan to diversify the source of our energy supply, we are seriously considering the import of LNG in 1990 in an annual amount of about one million tonnes. An additional half million tonnes per annum are expected to be imported after mid 1990's. In the year 2000, the total import may reach two million tonnes annually. It may be difficult to expect, based on your present plan, to complete developing the North Slope natural gas, and to meet our initial LNG requirements in 1990. We are, however, very interested in considering North Slope national gas as an alternative source for our energy requirement in the 1990's, if its price and freight are competitive.

The Pacific Rim countries will not be the only foreign beneficiaries of the TAGS Project. Canada stands to receive great economic benefits by continuing in its role as a

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45/ See, Exhibit D hereto at p. 1.

supplemental natural gas supplier to the Lower 48 states. Canadian gas reserves have become increasingly competitive with U.S. production and, according to a recent joint task force study issued by the American and Canadian Gas Associations, 46/ Canadian gas exports represented the largest foreign source of energy for the U.S. in 1986. Indeed, over the past 15 years, Canada has received approximately $33 billion (U.S.) in revenues for gas sold in the U.S. 47/ Canada's significant role as a competitive and major supplier of supplementary natural gas supplies to the U.S. market will continue undisturbed by the TAGS Project. The ANGTS Project, on the other hand, would only serve to displace our competitive and abundant 48/ Canadian supplies with surplus natural gas at an unconscionable cost.

D. Benefits to the State of Alaska

The TAGS Project will benefit Alaska by assisting in the development of its natural resources, introducing new industry into the state, providing new jobs, and creating an expanded tax base. These benefits are vitally important to the economic

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46/ The American Gas Association/Canadian Gas Association Joint Task Force, "Long-term U.S.-Canadian Natural Gas Trade" (September 1987).

47/ Id.

48/ The Joint Task Force Report estimates Canada's gas resource base to be over 73 Tcf in conventional areas, with an additional frontier area supply of at least 35 Tcf.

future of the nation's least developed and largest state, a last frontier seeking the economic base to develop the transportation and commercial infrastructure so taken for granted in older states.

The construction phase of the TAGS facilities will require a work force of approximately 10,000 construction personnel. Once operational, TAGS' day-to-day operations will require a permanent staff of at least 500 personnel, which would make Yukon Pacific one of Alaska's largest private employers. Significantly, approximately 10,000 additional indirect employment opportunities will be created during the construction phase of the project, while an additional 200 indirect permanent positions will be created during project operations. 49/

The TAGS Project will also serve to foster the creation of value added industries, particularly in and around the cities of Valdez and Fairbanks. For example, TAGS natural gas may serve as feedstock for new fertilizer, methanol, and petro-chemical plants. 50/ Communities straddling the route of the TAGS line

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49/ See, Harding Lawson Associates, "Trans-Alaska Gas System Draft Environmental Impact Statement, September 1987, at pp.4-10 (incorporated herein by reference as Exhibit K).

50/ See The Dow-Shell Group, "Alaska Petro Chemical Industry Feasibility Study - A Report to the State of Alaska," (September 9, 1981), and Commonwealth North Action Paper, "Moving North Slope Natural Gas to Market," (December 1981) Anchorage, Alaska.

will be introduced to a clean, efficient, and, in most cases, less expensive source of energy.

Alaska's economy is primarily based on revenues from its natural resource development. Revenues to state government have already sagged due to the recent oil price declines. Revenues are expected to decline even further when Prudhoe Bay oil production decreases in the late 1980's. Revenues from the TAGS Project will accrue to the state as an owner of the royalty portion of the gas Yukon Pacific purchases, as well as from gross production taxes and taxes on new employment and on the system itself, thereby improving the state's economy. Local ad valorem or similar taxes based on pipeline facilities will bring revenues to municipalities throughout the length of the TAGS facilities. Federal income taxes will also be collected. The State of Alaska will benefit tremendously from royalty revenues associated with the sale to Yukon Pacific of the now dormant North Slope reserves. Estimates of State of Alaska revenues accruing from the TAGS Project range from $1-3 million per day.

E. Other Considerations

1. The development of a transportation system to deliver North Slope reserves to market will undoubtedly accelerate current oil and gas exploration efforts and, importantly, stimulate new exploration;

2. The TAGS Project represents significant opportunities for domestic suppliers of high-grade steel, cargo transportation, and other required materials and services for completion and operation of the TAGS Project;

3. Yukon Pacific's exportation of LNG will ensure that the United States' Pacific Rim allies will avoid being excessively reliant upon Soviet and Persian Gulf energy supplies, thereby helping to create a global balancing of supply;

4. Authorization of the TAGS Project will inject an element of competition in the development of North Slope natural gas reserves which should prove healthy to both United States and Canadian entities seeking to bring natural gas to their respective domestic markets; and

5. Once appropriate regulatory approvals are in place, the risks and costs associated with the completion and operation of the TAGS Project, including the marketing of the gas, will be borne by the Project's private sponsors and investors. In addition, the TAGS Project facilities will not be "used and useful" to United States' taxpayers. Therefore, the United States'

taxpayer will not be required to bear any of these risks or costs.

IX.

ENVIRONMENTAL IMPACT

The nature of the actions required to approve the TAGS Project have led to the determination that, when viewed in the aggregate, it would constitute a major federal action within the meaning of the National Environmental Policy Act of 1969 (NEPA). 51/ In addition, because of the nature and potential magnitude of the TAGS Project, the resources involved, and the human and physical environmental concerns, these actions could have a significant effect on the human environment and thereby require the preparation of an Environmental Impact Statement (EIS).

Therefore, in accordance with NEPA and the Council on Environmental Quality Regulations promulgated thereunder, 52/ the Department of Interior, Bureau of Land Management (BLM), and the Department of the Army, Corps of Engineers (Corps), have been designated co-lead agencies in the preparation of a TAGS Project EIS. The Draft Environmental Impact Statement (DEIS) 53/ for the TAGS Project was issued in September, 1987, and formal public

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51/ 42 U.S.C. §§ 4321, *et seq* (1982).

52/ 40 C.F.R. §§ 1500-1508 (1987).

53/ *See* Note 48, *supra*.

hearings to accept public testimony and comments on the adequacy of the DEIS were conducted by the BLM and the Corps in October, 1987. All comments on the DEIS were due November 20, 1987.

The DEIS incorporates as Appendix K a study conducted by the Argonne National Laboratory to assess and examine the potential environmental consequences in the Lower 48 states arising from the export of North Slope natural gas contemplated by the TAGS Project. 54/ The Study addresses the environmental residual effects associated with using other fossil fuels to meet demand in the Lower 48 states in the event the export authority sought by Yukon Pacific is granted. These effects are studied under two scenarios. The first scenario, referred to in the Study as the "Maximum Residuals Scenario", involves an incremental demand in the Lower 48 states for energy in an amount equal to the volume contemplated for export by the TAGS Project, with no other gas available from domestic sources, including the North Slope. The second scenario, referred to in the Study as the "Intermediate Scenario", assumes available domestic gas supplies competing under normal market forces (assuming North Slope and increased import supplies are not available) for the various types of energy supply (coal, oil, and natural gas). The residual pollutants studied are nitrogen oxide, sulphur dioxide,

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54/ Energy and Environmental Systems Division of Argonne National Laboratory, "An Assessment of the Potential Environmental Residuals in the Lower 48 States Arising from Alaskan Natural Gas Exports" (July 30, 1987).

particulate matter, ash, and sludge. The concentrations of the pollutants are analyzed by region. The Study concludes that the residual environmental effects under both scenarios are not significant.

Yukon Pacific undertakes to keep the ERA apprised of the progress of the environmental review being conducted by the BLM and the Corps and expects that any order issued by the ERA with respect to the instant application would be conditioned upon completion of that review. 55/

X.

RELATED AUTHORIZATIONS

Pursuant to Section 12 of the Alaska Natural Gas Transportation Act (ANGTA), 56/ the President of the United States is required to make a finding approving exports of natural gas from Alaska's North Slope region. The President's Economic Policy Council has reportedly conducted an inter-agency review in order to make a recommendation to the President under Section 12 of ANGTA. The request for a Presidential finding has been made by Yukon Pacific State of Alaska Governor Steve Cowper, and the Alaska Congressional delegation. Throughout this process, the Administration has reaffirmed its commitment to removing impediments for the sale of North Slope natural gas. Given the

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55/ See, Boundary Gas, Inc., 1 ERA (CCH) ¶ 70,539 at p. 72,190 (1982).

56/ 15 U.S.C. § 719j (1982).

long history of proposed alternative uses of this gas, the Administration, in cooperation with the Canadian government, has undertaken consultations on the effects of a Section 12 export finding. Yukon Pacific believes that a positive Presidential finding on the export question is forthcoming.

Pursuant to Section 3 of the Natural Gas Act, the Federal Energy Regulatory Commission has determined that it is required to approve or disapprove of Yukon Pacific's proposed place of export of the LNG that is the subject of this export application. Yukon Pacific is filing concurrently herewith an application for an Order authorizing a place of export for the LNG in accordance with a recent Commission Declaratory Order. 57/

Section 103 of the Energy Policy Conservation Act 58/ empowers the President to restrict exports of natural gas by rule and under such terms and conditions as he determines appropriate and necessary to carry out the provisions of that Act. Yukon Pacific is not aware of any natural gas export restrictions imposed by the President pursuant to his Section 103 authority.

Yukon Pacific has filed an application for federal right-of-way with the Department of Interior, Bureau of Land

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57/ See, Yukon-Pacific Corp., 39 FERC (CCH) ¶ 61,216 (1987), reh'g denied, 40 FERC (CCH) ¶ 61,164 (1987), appealed sub nom. Foothills Pipe Line (Yukon) Ltd. v. FERC, Case No. 1541 and Alaskan Northwest Natural Gas Transportation Co. v. FERC, Case No. 87-1540 (D.C. Cir. Oct. 1, 1987).

58/ 42 U.S.C. § 6212 et seq (1982).

Management, [59] and for appropriate permits from the U.S. Department of the Army, Corps of Engineers. Numerous other less significant federal and state permits and authorizations have been, or, at the appropriate time, will be acquired by Yukon Pacific in the development of the TAGS Project.

XI.

NEED FOR EXPEDITED ACTION

The timing of the ERA's issuance of the export authorization sought by this Application is critical to the feasibility of the TAGS Project. It is unrealistic to expect that the TAGS Project sponsors can successfully secure firm commitments from the targeted Pacific Rim markets without first securing the ERA's requisite export approval. Such a scenario would entail putting the proverbial "cart before the horse." Moreover, a delay of even a few months could cause Yukon Pacific and the United States to lose an $80 billion market for these abundant North Slope reserves to Indonesian and other competing

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59/ See "Receipt of Right-of-Way Application for Construction of Gas Pipeline System", 49 Fed. Reg. 20945 (May 17, 1984); "Availability of Environmental Impact Statements for Natural Gas Pipeline Right-of-Way and Dredging Permits Between Prudhoe and Anderson Bays Near Valdez, AK", 51 Fed. Reg. 41512 (November 17, 1986).

foreign suppliers. 60/ It is therefore respectfully urged that this Application be acted upon expeditiously.

XII.

EXHIBITS

In accordance with Sections 103(c) and 201 of the ERA's Administrative Procedures 61/, the following exhibits are appended hereto:

Exhibit A - Opinion of Counsel

Exhibit B - By-laws and Articles of Incorporation of Yukon Pacific Corporation

Exhibit C - Form of Notice of Application for Export Authorization

Exhibit D - Joint Policy Statement on Japan-U.S. Energy Cooperation

Exhibit E - Alaska Asian Gas System (AAGS) Pre-feasibility Study

Exhibit F - Institute of Gas Technology Study

Exhibit G - Defined and producing North Slope natural gas reserves

Exhibit H - Undefined and non-producing North Slope natural gas reserves

Exhibit I - Compilation of Gas Supply Figures and Bibliography

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60/ Among the current and potential major LNG suppliers to Japan, the U.S. stands to benefit the most from exports of LNG to Japan. Figures supplied by the Embassy of Japan indicate that in 1986 Japan had a trade surplus with the U.S. of $57.63 billion and a trade deficit with all other foreign LNG suppliers. See Exhibit J hereto.

61/ 10 C.F.R. §§ 590.103(c) and 590.201 (1987).

Exhibit J - Japanese Trade Statistics with LNG Supplier Countries

Exhibit K - Draft Environmental Impact Statement 62/

Exhibit L - Economic Impact Analysis 63/

XIII. CONCLUSION

WHEREFORE, in consideration of the foregoing, Yukon Pacific respectfully requests that the ERA issue an order pursuant to Section 3 of the Natural Gas Act authorizing Yukon Pacific to export from the United States up to 14 million metric tons of LNG annually to the Pacific Rim, with volume flexibility to handle market requirements, for a term of 25 years beginning on the date of first delivery, which is presently estimated to be some time in 1996.

62/ Due to the voluminous nature of this Exhibit, and its availability to the public as part of the environmental review process, Yukon Pacific is omitting it from inclusion herein, but incorporates it herein by reference.

63/ To be supplied by Amendment.

Respectfully submitted,

YUKON PACIFIC CORPORATION

By: Patrick [signature]

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Patrick C. Rock
Reynolds Shannon Miller Blinn
White & Cook
1667 K Street, N.W., Suite 300
Washington, D.C. 20006
(202) 293-7777

Jeffrey B. Lowenfels, Esquire
of Birch, Horton, Bittner,
Pestinger and Anderson, and
General Counsel to
Yukon Pacific Corporation
P.O. Box 101700
Anchorage, Alaska 99501
(907) 279-1596

Dated: December 3, 1987

A

REYNOLDS SHANNON MILLER BLINN WHITE & COOK

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December 3, 1987

Economic Regulatory Administration
Forrestal Building
1000 Independence Ave., S.W.
Washington, D.C. 20585

Re: <u>Compliance with 10 C.F.R. § 590.202(c)</u>

Dear Sir or Madam:

We have examined the Amended Certificate of Incorporation, the Articles of Incorporation, as duly amended, and the Amended and Restated By-Laws of Yukon Pacific Corporation (Yukon Pacific) in recognition of the requirements of Section 202(c) of the Administrative Procedures of the Economic Regulatory Administration (ERA) and, based upon said examination, are of the opinion that (i) the exportation of liquefied natural gas as proposed by Yukon Pacific in its Application for Export filed this day with the ERA is within its corporate powers, and (ii) Yukon Pacific has either complied with, or is in the process of complying with, the corporate laws of the State of Alaska.

Very truly yours,

REYNOLDS SHANNON MILLER BLINN
WHITE & COOK

By: Robert W. Perdue
Robert W. Perdue
Counsel to Yukon Pacific
Corporation

B

FILED FOR RECORD
STATE OF ALASKA
FEB 4 1983

DEPARTMENT OF COMMERCE
& ECONOMIC DEVELOPMENT

ARTICLES OF INCORPORATION
OF
YUKON PACIFIC CORPORATION

I, the undersigned, natural person over the age of nineteen (19) years or more, acting as incorporator of a corporation under the Alaska Business Corporation Act, adopt the following Articles of Incorporation for such corporation:

ARTICLE I.

Name. The name of the corporation shall be YUKON PACIFIC CORPORATION.

ARTICLE II.

Period of Existence. The period of existence of this corporation shall be perpetual.

ARTICLE III.

Purposes. The purpose or purposes for which this corporation is organized are to engage in any legitimate business anywhere in the world and all activities directly and indirectly related thereto and all other corporate activities authorized by the laws of the State of Alaska.

SENT BY:Yukon Pacific Corp. ;11-30-87 10:23AM ; 9072760055→ 2022236734;# 3

ARTICLE IV.

Powers. The corporation is empowered to do any and all of the following:

(1) To borrow any amount of money, issue notes, bonds, securities or debentures of any type and pledge and secure the payment of the same with corporate assets.

(2) To enter into, make and perform contracts of every kind, with any persons, firm, association or corporation, municipality, state, government or foreign country; and without limit as to amount, to make, draw, accept, endorse, execute, discount and issue promissory notes, bills of exchange, drafts, warrants, debentures, bonds and other negotiable or transferable instruments and evidences of indebtedness, whether secured by mortgage or otherwise as far as permitted by the laws of the State of Alaska.

(3) To manufacture, purchase or acquire in any lawful manner, and to hold, pledge, mortgage, transfer, sell or dispose of in any manner; and to deal in trade and goods, merchandise and real and personal property of any and every class and description.

(4) To acquire the good will, rights and property and to undertake the whole or any part of the assets or liabilities of any person, firm, association, corporation; to pay for the same in cash or stock of this corporation in bonds or otherwise; to hold or in any lawful manner to dispose of the whole or any part of the properties so purchased; to conduct in any lawful manner the whole or any part of any business so acquired; and exercise any powers necessary or convenient in or about the conduct or management of such business.

(5) To hold, sell, guarantee, assign, mortgage, transfer, pledge or otherwise dispose of the shares of capital stock or bonds, securities or any evidences of indebtedness created by any other corporation or corporations of this state, any other state, territory or possession of the United States of America or for any foreign country, and while owners of said stock to exercise all the rights, powers and privileges of ownership, including the right to vote thereon, to the same extent as natural persons might or could do.

(6) To do all acts and exercise all powers permitted by A.S. 10.05.09 of the Alaska statutes.

ARTICLE V.

Enumeration of Powers. The powers granted herein to this corporation in Article IV are in furtherance of, and not in limitation of, the general powers conferred on corporations by the laws of the State of Alaska, and the corporation shall have and exercise all the powers specified under those laws.

ARTICLE VI.

Maximum Indebtedness. The corporation will have no limit as to the indebtedness it can incur at any one time.

ARTICLE VII.

Authorized Shares. The aggregate number of shares which the corporation is authorized to issue is 10,000, all of which shall become common voting stock with no par value.

ARTICLE VIII.

Preemptive Powers. The holders of the shares of the corporation shall have the preemptive right to purchase at such respective equitable prices, terms and conditions as shall be fixed by the Board of Directors such of the shares of the corporation as may be issued from time to time, over and above the initial issue, which have never been previously sold. Such preemptive rights shall apply to all shares issued after such initial issue, whether such additional shares constitute a part of the shares presently or subsequently authorized or constitute shares held in a manner prescribed by the Board of Directors.

ARTICLE IX.

Regulation of the Internal Affairs of the Corporation.

SECTION 1. Meetings of the Shareholders. Meetings of the shareholders of the corporation may be held at such place, either within or without the State of Alaska, as may be provided by the By-Laws. In the absence of any such provisions, all meetings shall be held at the registered office of the corporation.

SECTION 2. Meetings of Directors. Meetings of the Board of Directors of the corporation, regular of special, may be held either within or without the State of Alaska as may be provided in the By-Laws. In the absence of any such provisions, all meetings shall be held at the registered office of the corporation.

SECTION 3. By-Laws. The initial By-Laws of the corporation shall be adopted by the Board of Directors. The power to alter, amend or repeal the By-Laws or to adopt new By-Laws shall be vested in the Board of Directors. The By-Laws may contain any provisions for the regulation and management of the affairs of the corporation not inconsistent with the Articles of Incorporation.

SECTION 4. Amendments to Articles of Incorporation. The corporation reserves the right from time to time to amend, alter, or repeal or to add any provision to its Articles of Incorporation in the manner prescribed by law.

ARTICLE X.

Address of Initial Registered Office and Name of Initial Registered Agent. The address of the initial registered office of the corporation is 1127 West Seventh Avenue, Anchorage, Alaska 99501 and the name of the initial registered agent at such address is Ronald G. Birch.

SENT BY:Yukon Pacific Corp. ;11-30-87 10:25AM ; 9072760055→ 2022236734;# 7

ARTICLE XI.

Number and Names of the Board of Directors. The number of directors constituting the initial Board of Directors is one (1) and the name and address of the person who is to serve as director until the first annual meeting of the shareholders or until his successors are elected and shall qualify is:

Name	Address
Lawrence J. Kelley	SUPRA Corporation 1300 Pennzoil Place 700 Milam Street Houston, Texas 7002-2807

The number of directors may be increased or decreased by amendment of the By-Laws; but no decrease shall have the effect of shortening the term of any incumbent director.

ARTICLE XII.

Name and Address of Incorporator. The name and address of each incorporator:

Name	Address
Lawrence J. Kelley	SUPRA Corporation 1300 Pennzoil Place 700 Milam Street Houston, Texas 77002-2807

ARTICLE XIII.

The name and address of each affiliate which is a nonresident alien or corporation whose place of incorporation is outside the United States: NONE.

SENT BY:Yukon Pacific Corp. ;11-30-87 10:26AM ; 9072760055→ 2022236734;# 8

ARTICLE XIV.

Amendments to Articles. These Articles of Incorporation may be changed, amended or altered as prescribed in the By-Laws at any special or annual meeting of the stockholders.

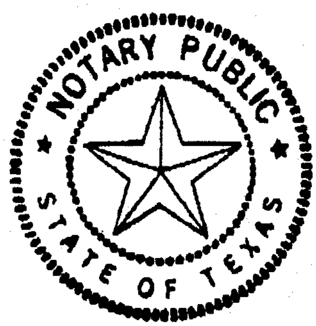
IN WITNESS WHEREOF, we have hereunto set our hands and seals this 26th day of January, 1983.

Lawrence J. Kelley

STATE OF TEXAS)
COUNTY OF HARRIS) ss

THIS IS TO CERTIFY that on this 26th day of JANUARY, 1983, before me, the undersigned, a Notary Public in and for the State of Texas, duly commissioned and sworn as such, personally appeared Lawrence J. Kelley, known to me and to me known to be the individual named in and who executed the foregoing instrument, and he acknowledged the execution thereof as his free and voluntary act and deed for the uses and purposes therein set forth.

IN WITNESS WHEREOF, I have hereunto set my hand and official seal the day and year first hereinabove written.



Juanita E. [illegible]
Notary Public in and for
Harris County, Texas

My commission expires: 9/1985

SIC CODE

The corporation's SIC code is: 1300 and 4600.

LJK/jep/YUKONdisc

FILED FOR RECORD
STATE OF ALASKA
JUN 2 0 1984
DEPARTMENT OF COMMERCE
& ECONOMIC DEVELOPMENT

ARTICLES OF AMENDMENT
TO THE
ARTICLES OF INCORPORATION
OF
YUKON PACIFIC CORPORATION

Pursuant to the provisions of the Alaska Business Corporation Act, the undersigned corporation adopts the following Articles of Amendment to its Articles of Incorporation. (A.S. 10.05.285)

FIRST: The name of the corporation is Yukon Pacific Corporation.

SECOND: The amendment adopted:

RESOLVED, that the shares of stock of this corporation be increased to 100,000 shares with a par value of $1.00 each.

THIRD: The above amendment was adopted by the shareholders on March 30, 1984.

FOURTH: There are 9,000 shares in the corporation entitled to vote.

FIFTH: There were 9,000 shares which voted for the amendment and 0 shares voted against the amendment.

SIXTH: The amendment does not provide for an exchange, reclassification or cancellation of issues shares.

SEVENTH: The amendment does not change the amount of stated capital in the corporation.

DATED: 5-11-84

YUKON PACIFIC CORPORATION

By [signature]
President

By [signature]
Secretary

VERIFICATION

L. Mead Treadwell, II, being the Secretary of the corporation, hereby states that the above Articles of Amendment of the corporation are true and correct and the above-entitled resolution was adopted by the shareholders of the corporation at a special meeting held the 30th day of ~~April~~ March 1984.

YUKON PACIFIC CORPORATION

[signature]
Secretary

STATE OF ALASKA)
) ss
THIRD JUDICIAL DISTRICT

THIS IS TO CERTIFY that on this 30th day of March, 1984 before me, the undersigned, a Notary Public in and for the State of Alaska, duly commissioned and sworn as such, personally appeared Mead Treadwell known to me to be the Corporate Secretary of Yukon Pacific Corporation, and as authorized representative of said corporation executed the foregoing instrument, and acknowledged that he executed said instrument as the free and voluntary act and deed of said corporation

SENT BY:Yukon Pacific Corp. ;11-30-87 10:28AM ; 9072760055→ 2022236734;#12

for the uses and purposes therein mentioned, and that he was authorized to execute said instrument.

WITNESS my official hand and seal the day and year in this certificate first hereinabove written.

Yvonne Lindblom
Notary Public in and for Alaska
My commission expires: 9-21-84

FILED FOR RECORD

[illegible] 1986

STATE OF ALASKA
DEPARTMENT OF COMMERCE
& ECONOMIC DEVELOPMENT

ARTICLES OF AMENDMENT

TO THE

ARTICLES OF INCORPORATION

OF

YUKON PACIFIC CORPORATION

Pursuant to the provisions of the Alaska Business Corporation Act, the undersigned corporation adopts the following Articles of Amendment to its Articles of Incorporation.

FIRST: The name of the corporation is Yukon Pacific Corporation.

SECOND: The amendment adopted is:

RESOLVED: The authorized shares of stock of this corporation be increased to 200,000 shares with a par value of $1.00 each.

THIRD: The above amendment was adopted by the shareholders on the 17th day of January, 1986.

FOURTH: There are 85,000 outstanding shares in the corporation entitled to vote.

FIFTH: There were 85,000 shares which voted for the amendment and 0 shares voted against the amendment.

SIXTH: The amendment does not provide for an exchange, reclassification or cancellation of issued shares.

SEVENTH: The amendment does not change the amount of stated capital in the corporation.

DATED: 17 January 1986

YUKON PACIFIC CORPORATION

By: Walter J Hickel
~~President~~ Chairman

By: [signature]
Secretary

VERIFICATION

I, L. Mead Treadwell, II, being the Secretary of the corporation, hereby state that the above Articles of Amendment of the corporation are true and correct and the above-entitled resolution was adopted by the shareholders of the corporation at a special meeting held on the 17th day of January, 1986.

YUKON PACIFIC CORPORATION

By: [signature]
Secretary

STATE OF ALASKA)
) ss.
THIRD JUDICIAL DISTRICT)

THIS IS TO CERTIFY that on this 17th day of January, 1986, before me, the undersigned, a Notary Public in and for the State of Alaska, duly commissioned and sworn as such, personally appeared Mead Treadwell, known to me to be the Corporate Secretary of Yukon Pacific Corporation, and as authorized representative of said corporation executed the foregoing instrument, and acknowledged that he executed said instrument as the free and voluntary act and deed of said corporation for the uses and purposes therein mentioned, and that he was authorized to execute said instrument.

WITNESS my official hand and seal the day and year in this certificate first hereinabove written.

Yvonne Lindblom
Notary Public in and for Alaska
My Commission Expires: 9-11-88

STATE OF ALASKA)
) ss.
THIRD JUDICIAL DISTRICT)

THIS IS TO CERTIFY that on this 17th day of January, 1986, before me, the undersigned, a Notary Public in and for the State of Alaska, duly commissioned and sworn as such, personally appeared WALTER J. HICKEL, known to me to be the ~~President~~ Chairman of Yukon Pacific Corporation, and as authorized representative of said corporation executed the foregoing instrument, and acknowledged that he executed said instrument as the free and voluntary act and deed of said corporation for the uses and purposes therein mentioned, and that he was authorized to execute said instrument.

WITNESS my official hand and seal the day and year in this certificate first hereinabove written.

Yvonne Lindblom
Notary Public in and for Alaska
My Commission Expires 9-11-88

AMENDED AND RESTATED BY-LAWS

OF

YUKON PACIFIC CORPORATION

ARTICLE I. OFFICES

The principal office of the corporation in the State of Alaska shall be located at Tiki Cove Building, 900 West 5th Avenue, Suite 730, Anchorage, Alaska 99501. The corporation may have such other offices, either within or without the State of Alaska as the Board of Directors may designate or as the business of the corporation may require from time to time.

ARTICLE II. SHAREHOLDERS

SECTION 1. Annual Meeting. The annual meeting of the shareholders of the corporation shall be held on such day during the three-month period following the close of the fiscal year as may be determined from time to time by the Board of Directors. At the annual meeting, the shareholders shall elect Directors for the ensuing year and may transact any general business which may be brought before the meeting and take any corporate action.

SECTION 2. Special Meetings. Special meetings of the shareholders, for any purpose or purposes, unless otherwise prescribed by statute, may be called by the President or the Board of Directors, and shall be called by the President at the request of the holders of not less than 60% of all the outstanding shares of the corporation entitled to vote at the meeting.

SECTION 3. Place of Meeting. All meetings of the shareholders shall be held at the principal office of the corporation, unless some other place is stated in the call.

SECTION 4. Notice of Meeting. Written notice stating the place, day and hour of the meeting and, in case of a special meeting, the purpose or purposes for which the meeting is called, shall, unless otherwise prescribed by statute or waived by the shareholders, be delivered not less than 10 days before the date of the meeting, either personally or by mail, by or at the direction of the President, or the Secretary, or the persons calling the meeting, to each shareholder of record entitled to vote at such meeting. If mailed, such notice shall be deemed to be delivered when deposited in the United States Mail, addressed to the shareholder at his address as it appears on the stock transfer books of the corporation, with postage thereon prepaid.

SECTION 5. Closing of Transfer Books or Fixing of Record Date. For the purpose of determining shareholders entitled to notice of or to vote at any meeting of shareholders or any adjournment thereof, or shareholders entitled to receive payment of any dividend, or in order to make a determination of shareholders for any other proper purpose, the Board of Directors of the corporation may provide that the stock transfer books shall be closed for a stated period, but not to exceed, in any case, thirty (30) days. If the stock transfer books shall be closed for the purpose of determining shareholders entitled to notice of or to vote at a meeting of shareholders, such books shall be closed for at least thirty (30) days immediately preceding such meeting. In lieu of closing the stock transfer books, the Board of Directors may fix in advance a date as the record date for any such determination of shareholders, such date in any case to be not more than fifteen (15) days. If the stock transfer books are not closed and no record date is fixed for the determination of shareholders entitled to notice of or to vote at a meeting of shareholders, or shareholders entitled to receive payment of a dividend, the date on which notice of the meeting is mailed or the date on which the resolution of the Board of Directors declaring such dividend is adopted, as the case may be, shall be the record date for such determination of shareholders. When a determination of shareholders entitled to vote at any meeting of shareholders has been made as provided in this section, such determination shall apply to any adjournment thereof.

SECTION 6. <u>Voting Lists</u>. The officer or agent having charge of the stock transfer books for shares of the corporation shall make a complete list of shareholders entitled to vote at each meeting of shareholders or any adjournment thereof, arranged in alphabetical order, with the address and the number of shares held by each. Such list shall be produced and kept open at the time and place of the meeting and shall be subject to the inspection of any shareholder during the whole time of the meeting for the purposes thereof.

SECTION 7. <u>Quorum</u>. A majority of the outstanding shares of the corporation entitled to vote, represented in person or by proxy, shall constitute a quorum at a meeting of shareholders. If less than a majority of the outstanding shares are represented at a meeting, a majority of the shares so represented may adjourn the meeting from time to time without further notice. At such adjourned meeting at which a quorum shall be present or represented, any business may be transacted which might have been transacted at the meeting as originally noticed. The shareholders present at a duly organized meeting may continue to transact business until adjournment, notwithstanding the withdrawal of enough shareholders to leave less than a quorum.

SECTION 8. <u>Proxies</u>. At all meetings of shareholders, a shareholder may vote in person or by proxy executed in writing by the shareholder or his duly authorized attorney in fact. Such proxy shall be filed with the secretary of the corporation before or at the time of the meeting. No proxy shall be valid after six months from the date of its execution, unless otherwise provided in the proxy.

SECTION 9. Voting of Shares. Subject to the provisions of Section 12 of this Article II, each outstanding share entitled to vote shall be entitled to one vote upon each matter submitted to a vote at a meeting of shareholders.

SECTION 10. Voting of Shares by Certain Holders. Shares standing in the name of another corporation may be voted by such officer, agent or proxy as the by-laws of such corporation may prescribe or, in the absence of such provisions, as the Board of Directors of such corporation may determine.

SECTION 11. Informal Action by Shareholders. Unless otherwise provided by law, any action required to be taken at a meeting of the shareholders, or any other action which may be taken at a meeting of the shareholders, may be taken without a meeting if a consent in writing, setting forth the action so taken, shall be signed by all of the shareholders entitled to vote with respect to the subject matter thereof.

SECTION 12. Cumulative Voting. There shall be no cumulative voting.

SECTION 13. Special Actions of Shareholders. The following, if submitted to a vote of shareholders, shall require the affirmative vote of not less than 75% of the total number of shares then outstanding (1) the adoption of any amendment to the Articles of Incorporation or By-Laws of the corporation, (2) approval of any merger or consolidation, exchange of stock, sale of substantially all of the assets of the corporation, dissolution or similar transaction or (3) approval of any contract, agreement, purchase, sale, or other transaction in which any shareholder, director or a related party has a direct financial interest.

ARTICLE III. BOARD OF DIRECTORS

SECTION 1. General Powers. The Board of Directors shall manage the property and business of the corporation and shall have and may exercise all of the powers of the corporation except such as are reserved to or may be conferred upon the shareholders of the corporation.

The Board shall have the power to make and change from time to time rules and regulations not inconsistent with these By-Laws for the management of the business and affairs of the corporation.

SECTION 2. Number, Tenure and Qualifications. The number of directors of the corporation shall be nine (9). Each director shall hold office until the next annual meeting of shareholders and until his successor shall have been designated and elected.

SECTION 3. Regular Meetings. A regular meeting of the Board of Directors shall be held without other notice than this By-Law immediately after, and at the same place as, the annual meeting of shareholders. The Board of Directors may provide, by resolution, the time and place for the holding of additional regular meetings without other notice than such resolution.

SECTION 4. Special Meetings. Special meetings of the Board of Directors may be called by or at the request of the President or any two directors. The person or persons authorized to call special meetings of the Board of Directors may fix the place for holding any special meeting of the Board of Directors called by them.

SECTION 5. Notice. Notice of any special meeting shall be given at least fifteen (15) days previously thereto by written notice delivered personally or mailed to each director at his business address or by telegram. If mailed, such notice shall be deemed to be delivered when deposited in the United States Mail so addressed, with postage thereon prepaid. If notice be given by telegram, such notice shall be deemed to be delivered when the telegram is delivered to the telegraph company. Any director may waive notice of any meeting. The attendance of a director at a meeting shall constitute a waiver of notice of such meeting, except where a director attends a meeting for the express purpose of objecting to the transaction of any business because the meeting is not lawfully called or convened.

SECTION 6. Quorum. The quorum of the Board of Directors shall be a majority of the Directors and any resolution or other action taken at a meeting of the Board of Directors shall be adopted by an affirmative vote of a majority of the Directors.

SECTION 7. Action Without a Meeting. Any action that may be taken by the Board of Directors at a meeting may be taken without a meeting if a consent in writing, setting forth the action so to be taken, shall be signed by all the Directors.

SECTION 8. Vacancies. Any vacancy occurring in the Board of Directors may be filled by the Board of Directors as soon as practicable. A director elected to fill a vacancy caused by death, resignation or removal, or by reason of an increase in the number of directors shall be elected for the unexpired term of his predecessor or other directors in the office.

SECTION 9. Compensation. By resolution of the Board of Directors, each director who is not an employee of the corporation may be paid his expenses, if any, of attendance at each meeting of the Board of Directors, and may be paid a stated salary as director or a fixed sum for attendance at each meeting of the Board of Directors or both.

SECTION 10. Presumption of Assent. A director of the corporation who is present at a meeting of the Board of Directors at which action on any corporate matter is taken shall be presumed to have assented to the action taken unless his dissent shall be entered in the minutes of the meeting or unless he shall file his written dissent to such action with the person acting as the secretary of the meeting before the adjournment thereof or shall forward such dissent by registered mail to the secretary of the corporation immediately after the adjournment of the meeting. Such right to dissent shall not apply to a director who voted in favor of such action.

SECTION 11. Meeting by Telephone Conference. Any meetings of Shareholders, Board of Directors, or the Executive Committee may occur by telephone conference.

SECTION 12. Executive Committee. There shall be an Executive Committee of the Corporation consisting of three (3) members of the Board of Directors. The Executive Committee shall have the maximum authority permitted under the laws of the State of Alaska. All actions by the Executive Committee shall require unanimous approval of all members.

SECTION 13. <u>Special Actions of Directors.</u> The following actions by the Board of Directors shall require the affirmative vote of not less than 75% of the total numbers of directors: (1) adoption of any amendment to the By-Laws or the proposal to the shareholders of any amendment to the Articles of Incorporation, (2) the approval of any merger, consolidation, exchange of stock, sale of substantially all of the assets of the corporation, dissolution, or similar transaction, (3) approval of service contracts to be entered into by the corporation requiring payments in excess of $100,000.00 a year, (4) payment of dividends to shareholders, (5) approval of long term contracts and leases, (6) authorization or issuance of additional shares, whether treasury shares or previously unissued shares, or stock options, (7) approval of legal counsel and public accountants who shall certify the annual financial statements of the company, (8) borrowing money, establishing a line of credit or pledging corporate assets and (9) approval of any contract, agreement or purchase, sale or other transaction in which any shareholder, director or related party has a direct financial interest.

SECTION 14. Indemnification of Directors. The Corporation shall indemnify any and all persons who may serve or who have served at any time as directors or officers of the corporation and their respective heirs, administrators, successors, and assigns, against any and all expenses, including amounts paid upon judgments, counsel fees, and amounts paid in settlement (before or after suit is commenced), actually and necessarily incurred by such persons in connection with the defense or settlement of any claim, action, suit, or proceeding, in which they, or any of them, are made parties, or a party, or which may be asserted against them or any of them, by reason of being or having been directors or officers or a director or officer of the Corporation, except in relation to matters as to which any such director or officer, or former director, or officer, or person, shall be adjudged in any action, suit, or proceeding, to be liable for his own negligence or misconduct in the performance of his duty. Such indemnification shall be in addition to any other rights to which those indemnified may be entitled under any law, by-law, agreement, vote of stockholders, or otherwise.

ARTICLE IV. OFFICERS

SECTION 1. Number. The officers of the corporation shall be a Chairman of the Board, a Vice-Chairman, a

President, a Vice President, a Secretary and a Treasurer, each of whom shall be elected by the Board of Directors. Such other officers and assistant officers as may be deemed necessary may be elected or appointed by the Board of Directors. One individual may hold more than one office.

SECTION 2. Election and Term of Office. The officers of the corporation to be elected by the Board of Directors shall be elected annually by the Board of Directors at the first meeting of the Board of Directors held after each meeting of the shareholders. If the election of officers shall not be held at such meeting, such election shall be held as soon thereafter as conveniently may be. Each officer shall hold office until his successor shall have been duly elected and shall have qualified or until his death or until he shall resign or shall have been removed in the manner hereinafter provided.

SECTION 3. Removal. Any officer may be removed by the Board of Directors whenever in its judgment, the best interests of the corporation will be served thereby, but such removal shall be without prejudice to the contract rights, if any, of the person so removed. Election or appointment of an officer shall not of itself create contract rights.

SECTION 4. Vacancies. A vacancy in any office because of death, resignation, removal, disqualification or otherwise, may be filled by the Board of Directors for the unexpired portion of the term.

SECTION 5. Chief Executive Officer. Either the President or Chairman of the Board may be designated Chief Executive Officer by the Board of Directors. The Chief Executive Officer shall be the principal executive officer of the corporation and, subject to the control of the Board of Directors, shall in general supervise and control all of the business and affairs of the corporation. He may sign, with the Secretary and/or Treasurer or any other proper officer of the corporation thereunto authorized by the Board of Directors, certificates for shares of the corporation, any deeds, mortgages, bonds, contracts or other instruments which the Board of Directors has authorized to be executed, except in cases where the signing and execution thereof shall be expressly delegated by the Board of Directors or by these By-Laws or some other officer or agent of the corporation, or shall be required by law to be otherwise signed or executed; and in general shall perform all duties incident to the office of President and such other duties as may be prescribed by the Board of Directors from time to time.

SECTION 6. Shareholder/Board of Director Meetings. The Chairman of the Board, if there is one, shall preside at all shareholder/Board of Director meetings. If there is no

Chairman, or if he is absent, the President shall preside at such meetings.

SECTION 7. Vice President or Vice Chairman. In the event of the death or inability of the Chairman of the Board or President, the Vice Chairman or Vice President shall perform the duties of the Chairman or President, respectively, until the succeeding Chairman or President is elected, and while so acting, shall have all the powers of and be subject to all the restrictions upon the Chairman or President. The Vice Chairman or Vice President shall perform such other duties as from time to time may be assigned to him by the Board of Directors.

SECTION 8. Secretary. The Secretary shall: (a) keep the minutes of the proceedings of the shareholders and of the Board of Directors in one or more books provided for that purpose; (b) see that all notices are duly given in accordance with the provisions of these By-Laws or as required by law; (c) be custodian of the corporate records and of the seal of the corporation and see that the seal of the corporation is affixed to all documents, the execution of which on behalf of the corporation under its seal is duly authorized; (d) keep a register of the post office address of each shareholder which shall be furnished to the Secretary by such shareholder; (e) sign with the President, certificates of shares of the corporation, the issuance of which shall have been authorized by resolution of the Board of Directors; (f) have general charge of the stock transfer books of the corporation; and (g) in general perform all duties incident to the office of Secretary and such other duties as from time to time may be assigned to him by the president or by the Board of Directors.

SECTION 9. Treasurer. The Treasurer shall, subject to the Board of Directors, have general charge of the financial records of the corporation.

SECTION 10. Salaries. The salaries of the officers shall be fixed from time to time by the Board of Directors and no officers shall be prevented from receiving such salary by reason of the fact that he is also a director of the corporation.

ARTICLE V. CONTRACTS, LOANS, CHECKS AND DEPOSITS

SECTION 1. Contracts. The Board of Directors may authorize any officer or officers, agent or agents, to enter into any contract or execute and deliver any instrument in the name of and on behalf of the corporation, and such authority may be general or confined to specific instances.

SECTION 2. Loans. No loans shall be contracted on behalf of the corporation and no evidence of indebtedness shall be issued in its name unless authorized by a resolution of the Board of Directors. Such authority may be general or confined to specific instances.

SECTION 3. Checks, Drafts, Etc. All checks, drafts or other orders for the payment of money, notes or other evidences of indebtedness issued in the name of the corporation, shall be signed by such officer or officers, agent or agents of the corporation and in such manner as shall from time to time be determined by resolution of the Board of Directors.

SECTION 4. Deposits. All funds of the corporation not otherwise employed shall be deposited from time to time to the credit of the corporation in such banks, trust companies or other depositories as the Board of Directors may select.

ARTICLE VI. CERTIFICATES FOR SHARES AND THEIR TRANSFER

SECTION 1. Certificates for Shares. Certificates representing shares of the corporation shall be in such form as shall be determined by the Board of Directors. Such certificates shall be signed by the President and by the Secretary or by such other officers authorized by law and by the Board of Directors to do so, and sealed with the corporate seal. All certificates of shares shall be consecutively numbered or otherwise identified. The name and address of the person to whom the shares represented thereby are issued, with the number of shares and date of issue, shall be entered on the stock transfer books of the corporation. All certificates surrendered to the corporation for transfer shall be cancelled and no new certificate shall be issued until the former certificate for a like number of shares shall have been surrendered and cancelled, except that in case of a lost, destroyed or mutilated certificate, a new one may be issued therefor upon such terms and indemnity to the corporation as the Board of Directors may prescribe.

SECTION 2. Transfer of Shares. Transfer of shares of the corporation shall be made only on the stock transfer books of the corporation by the holder of record thereof or by his legal representative, who shall furnish proper evidence of authority to transfer, or by his attorney thereunto authorized by power of attorney duly executed and filed with the Secretary of the corporation, and on surrender for cancellation of the certificate for such shares. The person in whose name shares stand on the books of the corporation shall be deemed by the corporation to be the owner thereof for all purposes.

SECTION 3. Restriction of Transfer; Option to Purchase. The shares of this corporation are issued subject to the restrictions contained in that certain "Shareholders Agreement" dated January 27, 1986, a copy of which is contained in the files of the corporation.

ARTICLE VII. FISCAL YEAR

The fiscal year of the corporation shall begin on the 1st day of January, and end on the 31st day of December of each year.

ARTICLE VIII. DIVIDENDS

The Board of Directors may from time to time declare, and the corporation may pay dividends on its outstanding shares in the manner and upon the terms and conditions provided by the law and its articles of incorporation.

ARTICLE IX. WAIVER OF NOTICE

Unless otherwise provided by law, whenever any notice is required to be given to any shareholder or director of the corporation under the provisions of these By-Laws or under the provisions of the Articles of Incorporation or under the provisions of the Alaska Business Corporation Act, a waiver thereof in writing, signed by the person or persons entitled to such notice, whether before or after the time stated therein shall be deemed equivalent to the giving of such notice.

ARTICLE X. AMENDMENTS

These By-Laws may be altered, amended or repealed and new By-Laws may be adopted by a 75% affirmative vote of the number of Board of Directors at any regular or special meeting of the Board of Directors, or by a 75% affirmative vote of the outstanding shares in the Corporation.

ARTICLE XI. CORPORATE SEAL

The Board of Directors shall provide a corporate seal which shall be circular in form and shall have inscribed thereon the name of the corporation and the state of incorporation and the words "Corporate Seal."

CERTIFICATE

I hereby certify that the foregoing Amended and Restated By-Laws were duly presented to, and adopted by the shareholders of Yukon Pacific Corporation by a Consent of Shareholders dated the 31 day of October, 1986.

Secretary

Name and Address of each shareholder owning 3 percent or more of the shares of the corporation.

<u>Name & Address</u>

Walter J. and Ermalee Hickel
P.O. Box 101700
Anchorage, Alaska 99510

Lawrence J. Kelley
1300 Pennzoil Place
700 Milam
Houston, TX 77002

Loren H. Lounsbury
1143 M Court
Anchorage, Alaska 99501

William H. Bittner
1127 West 7th Avenue
Anchorage, Alaska 99051

Anne S. Thomas
404 Carnarvon
Houston, TX 77024

Daniel A. Casey
2020 Abbott
Anchorage, Alaska 99507

Neva M. Egan
2700 Arlington Drive
Anchorage, Alaska 99517

TXG Alaska, Inc.
P.O. Box 1160
Owensboro, Kentucky 42302

Mead Treadwell
900 West 5th Avenue, Suite 730
Anchorage, Alaska 99501

State of Alaska

Department of Commerce and Economic Development

Certificate

CERTIFICATE OF AMENDMENT

The undersigned, as Commissioner of Commerce and Economic Development of the State of Alaska, hereby certifies that duplicate originals of Articles of Amendment to the Articles of Incorporation, duly signed and verified pursuant to the provisions of the Alaska Business Corporation Act, have been received in this office and are found to conform to law.

ACCORDINGLY, the undersigned, as Commissioner of Commerce and Economic Development, and by virtue of the authority vested in him by law, hereby issues this Certificate of Amendment to the Articles of Incorporation of

YUKON PACIFIC CORPORATION

and attaches hereto a duplicate original of the Articles of Amendment.

THE SEAL OF THE STATE OF ALASKA

IN TESTIMONY WHEREOF, I execute this certificate and affix the Great Seal of the State of Alaska this

23rd day of January, A.D. 19 86

Loren H. Lounsbury

Loren H. Lounsbury
COMMISSIONER OF COMMERCE AND ECONOMIC DEVELOPMENT

C

[ERA DOCKET NO. ________________]

Liquefied Natural Gas Exports; Yukon Pacific Corporation; Application to Export Liquefied Natural Gas from Alaska

AGENCY: Department of Energy
Economic Regulatory Administration

ACTION: Notice of Application to Export Liquefied Natural Gas from Alaska

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SUMMARY:

The Economic Regulatory Administration (ERA) of the Department of Energy (DOE) gives notice of receipt on December 3, 1987 of an application from Yukon Pacific Corporation (Yukon Pacific) to export up to fourteen million metric tons of liquefied natural gas (LNG) annually from Port Valdez, Anderson Bay, Alaska, to the Pacific Rim countries of Japan, the Republic of Korea and the Republic of China (Taiwan). The export authority sought is for a primary term of twenty-five years commencing on the date of first delivery.

Yukon Pacific will purchase natural gas at Prudhoe Bay, Alaska and transport such gas through the Trans-Alaska Gas System (TAGS) pipeline to be constructed and operated by Yukon Pacific. The pipeline will originate at Prudhoe Bay and terminate at a tidewater site on Port Valdez, Anderson Bay, Alaska. The TAGS pipeline will transport up to 2.3 billion cubic feet (Bcf) of natural gas per day. Such natural gas will be liquefied at an LNG plant, which will be located at the pipeline terminus at Anderson Bay along the southern shoreline of Port Valdez. The LNG will then be loaded onto ocean transport vessels for shipment to the Pacific Rim markets. The associated purchase and sale agreements for such LNG will be executed by and between Yukon Pacific on its own behalf, as seller, and Pacific Rim Purchasers, as buyers, including, but not limited to, local distribution companies, electric utility companies and industrial end-users. The exports will be for Yukon Pacific's own account. The specific proposed terms of the North Slope purchases and the LNG sales are summarized in the application. The gas purchase and LNG sales agreements are to be supplemented.

Yukon Pacific represents that the proposed export is not inconsistent with the public interest and that there is a lack of

short and long-term domestic need for the North Slope natural gas its application contemplates for export as LNG. The application states that the export of North Slope LNG will significantly reduce Pacific Rim trade surpluses thereby benefitting the United States as a whole, and will provide numerous other benefits in the public interest, all as more fully described in Yukon Pacific's application.

The application was filed with the ERA pursuant to Section 3 of the Natural Gas Act and DOE Delegation Order No. 0204-111. Protests, motions to intervene, notices of intervention, and written comments are invited.

DATES:

Protests, motions to intervene, or notices of intervention, as applicable, and written comments are to be filed no later than ____________________.

FOR FURTHER INFORMATION CONTACT:

____
Office of Fuels Programs
Economic Regulatory Administration
Forrestal Building, Room GA-076
1000 Independence Avenue, S.W.
Washington, D.C. 20585

____
Office of General Counsel
U.S. Department of Energy
Forrestal Building, Room 6-E-042
1000 Independence Avenue, S.W.
Washington, D.C. 20585

PUBLIC COMMENT PROCEDURES:

In response to the notice, any person may file a protest, motion to intervene, or notices of intervention, as applicable, and written comments. Any person wishing to become a party to the proceeding and to have written comments considered as the basis for any decision on the application must, however, file a motion to intervene or notice of intervention, as applicable. The filing of a protest with respect to this application will not serve to make the protestant a party to the proceeding, although protests and comments received from persons who are not parties will be considered in determining the appropriate procedural action to be taken on the application. All protests, motions to intervene, notices of intervention, and written comments must meet the requirements that are specified by the regulations in 10 CFR Part 590. They should be filed with the Natural Gas Division, Office of Fuels Programs, Economic Regulatory Administration, Room GA-076-A, RG-23, Forrestal Building, 1000 Independence Avenue, S.W., Washington, D.C. 20585 (202) 252-9478. They must be filed no later than ______________ ______________.

The Administrator intends to develop a decisional record on the application through responses to this notice by parties, including the parties' written comments and replies thereto. Additional procedures will be used as necessary to achieve a complete understanding of the facts and issues. A party seeking intervention may request that additional procedures be provided, such as additional written comments, an oral presentation, a conference, or a trial-type hearing. Any request to file additional written comments should explain why they are necessary. Any request for an oral presentation should identify the substantial question of fact, law or policy at issue, show that it is material and relevant to a decision in the proceeding, and demonstrate why an oral presentation is needed. Any request for a conference should demonstrate why the conference would materially advance the proceeding. Any request for a trial-type hearing must show that there are factual issues genuinely in dispute that are relevant and material to a decision and that a trial-type hearing is necessary for a full and true disclosure of the facts.

If an additional procedure is schedule, the ERA will provide notice to all parties. If no party requests additional procedures, a final opinion and order may be issued based upon the official record, including the application and responses filed by parties pursuant to this notice, in accordance with 10 C.F.R. 590.316.

A copy of Yukon Pacific's application is available for inspection and copying in the Natural Gas Division Docket Room, GA-076-A, at the above address. The docket room is open between the hours of 8:00 A.M. and 4:30 P.M. Monday through Friday, except Federal holidays.

Issued in Washington, D.C., ______________, 1987.

D

Joint Policy Statement

on

Japan-U.S. Energy Cooperation

Prime Minister Nakasone and President Reagan shared the view that further progress be made in energy trade and co-operation in oil, natural gas and coal between Japan and the United States as outlined in the following Joint Policy Statement recommended by the Japan-United States Energy Working Group:

1. Taking account of the energy prospects for the entire Pacific Basin, the two countries agree that the sound expansion of US.-Japan energy trade will contribute to the further development of the close economic and energy security relationship which exists between the two countries.

2. They will continue to discuss and find ways of developing this trade for the mutual benefit of both countries, noting the importance of long-term cooperation, the central role of the private sector, and the need for a balance between economic cost and energy security.

3. Both countries consider Alaska to be a particularly promising area for joint development of energy resources. Both governments will encourage private sector discussions regarding the

possibilities for such development.

4. With regard to trade in oil, gas and coal, we have agreed on the following next steps:

a. The U.S. and Japan recognize that if legislative barriers can be removed, the U.S. has the potential to ship substantial quantities of crude oil to Japan, thereby increasing economic incentives for U.S. oil production and helping to diversify Japan's energy sources. The U.S. will continue to keep under review the removal of restrictions on exports of domestic crude oil.

b. The U.S. and Japan will encourage private industry in both countries to undertake now the pre-feasibility or feasibility studies necessary to determine the extent to which Alaskan natural gas can be jointly developed by U.S. and Japanese interests.

c. The U.S. and Japan will encourage private industry in both countries to discuss the possibility of concluding long-term coal contracts and jointly developing mines and transportation systems to make American coal more competitive in the Japanese market.

d. In this regard, the two countries welcome the examinations underway of the technical and economic aspects of several steam coal projects by private companies concerned on both sides. As economic recovery proceeds, Japan will encourage its industries to consider purchase of more competitively priced U.S. steam coal, to meet future demand not already covered by existing contracts. In addition, Japan will invite the private sector concerned to explore the possibility of further increasing substitution of coal for oil in electrical generation.

e. With regard to metallurgical coal, both sides noted that the depressed state of world steel manufacturing had reduced demand for traded coal. However, in view of the fact that the U.S. has been a major supplier to the Japanese market, both sides will endeavor to maintain the level of Japanese imports of U.S. coal. Japan expects that imports of competitively priced U.S. metallurgical coal will not continue to decline, and will encourage its steel industry to increase U.S. coal imports when conditions in the industry permit.

f. As a first step toward developing U.S.-Japan coal trade from mid-to-long term perspective, a mission composed of representatives of major Japanese coal users and other appropriate interests will visit the U.S. to meet with major coal mining and transportation interests. The purpose of this mission will be to explore the possibility of expanding coal trade between the U.S. and Japan, and the possibility of conducting a major study of the opportunities for reducing the delivered price in Japan of U.S. coal.

November 11, 1983

— Imports of U.S. Coal, Natural Gas at St. —

Japan, U.S. Agree on Energy

Japan and the U.S. agreed Friday to encourage private industries in both countries to look into the possibility of joint development of American coal and Alaskan natural gas for future exportation to Japan.

In announcing the joint policy statement on Japan-U.S. energy cooperation, the two governments also said that "both sides will endeavor to maintain the level of Japanese imports of U.S. coal."

But they failed to specify how much coal Japan will import from the U.S. This is because the amount of coal imports is expected to decline in the years to come due to high prices of American coal caused by transportation problems.

The agreement, based on four rounds of meetings of the Japan-U.S. energy working group, was reported to Prime Minister Yasuhiro Nakasone and President Ronald Reagan.

Japan and the U.S. decided to set up the working group in January when Nakasone visited the U.S. The group is to discuss the possibilities of cooperation in energy trade.

In the statement, Japan and the U.S. said that they will encourage private industries in both countries to undertake the feasibility studies necessary to determine the extent to which Alaskan natural gas can be jointly developed by Japanese and American firms.

The natural gas deposits in the Prudhoe Bay field in Alaska are estimated at 730 billion cubic meters, or 13 percent of the U.S.'s total deposits.

Japan and the U.S. also agreed to encourage private industries in both countries to discuss the possibility of concluding long-term coal contracts and jointly developing mines and transportation systems to make American coal more competitive in the Japanese market.

In fiscal 1982, Japan imported from the U.S. 19,809,000 tons of metallurgical coal or 31.8 percent of Japan's imported metallurgical coal and 1,388,000 tons of steam coal or 10.1 percent of Japan's imported steam coal.

Due to long land transportation routes, the price of American metallurgical coal was about 10 dollars higher per ton than the average import price and that of American steam coal about six dollars higher in fiscal 1982.

Unless American coal recovers its competitiveness, Japan's import of metallurgical coal from the U.S., for example, is expected to decline to about 14 million tons in fiscal 1983, to about 10 million tons in fiscal 1984 and to about two to three million tons in fiscal 1985.

In the policy statement, Japan pledged to encourage industries to consider purchases of "more competitively priced U.S. steam coal" to meet future demand not already covered by existing contracts, as economic recovery proceeds.

Japan also pledged to encourage its steel industry to increase U.S. metallurgical coal imports "when conditions in the industry permit."

As to the possible exportation of Alaskan oil to Japan, the U.S. only said that it will continue to "keep under review the removal of restrictions" on exports of domestic crude oil.

It is very difficult for the U.S. administration to remove the legal restrictions. On Oct. 27, the House of Representatives passed a resolution calling for the extension of the export Control Act of 1979, on which the restrictions are based, to Sept. 30, 1987.

The act was to have expired on Sept. 30 this year.

If the export of Alaskan oil is liberalized, it is said that about 70,000 barrels per day of oil will be available for export to Japan and Japanese firms are reported to be ready to buy 50,000 barrels per day.

An American official said, "We believe the export of oil is in the national interest."

But he said at the same time that although lifting the ban on oil exports is consistent with the Reagan administration's free trade policy, the issue is "very, very touchy" politically.

The Japan Times

November 12, 1983

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ALASKA ASIAN GAS SYSTEM

AAGS

PRE-FEASIBILITY STUDY
SUMMARY REPORT

MAY 1987

Alaska Asian Gas System

Pre-Feasibility Study

Introduction

On April 26, 1985, a Study Agreement was executed between ARCO, serving as the U.S. Sponsor Group Representative, and The Committee for Energy Policy Promotion, serving as the Japan Sponsor Group Representative, to undertake a joint pre-feasibility study program regarding a liquefied natural gas (LNG) project for natural gas produced from the North Slope of Alaska, U.S.A.

The LNG Project assumed delivery of natural gas existing in the North Slope area of Alaska through a 1,300 km (800 miles) pipeline system to South Alaska and liquefaction of the gas there for sale in Japan. The Pre-Feasibility Study Program was divided into three distinct studies as follows:

- Alaskan North Slope Natural Gas Reserves Study (conducted by the U.S. Operator)

- Delivery System Studies (further divided into "Alaskan Facilities Study" conducted by the U.S. Operator and "Other Facilities Study" conducted by the Japan Sponsor Group)

- Japan LNG Market Study (conducted by the Japan Operator)

The purpose of the Study Program was solely to conduct a pre-feasibility study to develop initial, conceptual evaluations of the Project. This pre-feasibility study did not encompass the actual construction or operation of an LNG facility or pipeline, nor the filing of an environmental impact statement. Participation in the study did not imply a commitment for the purchase or sale of LNG nor for conducting a feasibility study of the Project.

The work as defined in the Study Agreement has been completed. This Study Program Final Report integrates the separate studies for submission to the Sponsors.

The final report is organized in six sections:

Section I	Summary Report including: - Executive Summary - Discussion - Tables and Figures
Section II	North Slope Gas Reserves
Section III	Alaskan Facilities Overview
Section IV	Other Facilities Overview
Section V	Market Forecast
Section VI	Economic Analysis

On May 15, 1987, conclusions of this pre-feasibility study were presented to the executive Committee in Tokyo, Japan. The material discussed in this meeting has been included in Section I of this report.

The Executive Committee approved this report and the following key conclusions:

. Available market in Japan at project completion is insufficient for this large scale project and additional market outside Japan is needed for project success.

. Bridging supply is needed before 1998 to preserve the available market for AAGS.

Based on the above conclusions, the Executive Committee agreed that the current environmental factors do not warrant a formal Bridging I (the next step as defined in the project schedule). However, both sides will maintain informal contacts to continually re-evaluate a need for the formal Bridging I.

I. EXECUTIVE SUMMARY

1. CONCLUSION

- THE CONCEPTUAL DESIGN AND COST ESTIMATES ARE BASED ON DELIVERING 14 MILLION TONS A YEAR OF LNG AND THE MARKET DEMAND FORECAST HAS BEEN LIMITED TO JAPAN ONLY.

- THE PROJECT COST FOR THE FACILITIES IN ALASKA WHICH INCLUDE A GAS CONDITIONING PLANT, PIPELINE SYSTEM AND LIQUEFACTION - STORAGE - LOADING TERMINAL IS ESTIMATED AT $8.64 BILLION IN 1986 CONSTANT DOLLARS.

- NEEDED LNG CARRIERS ARE ESTIMATED TO COST $2.37 BILLION.

- THE PROJECT REQUIRES ELEVEN YEARS IN THE STANDARD CASE TO COMPLETE INCLUDING TWO BRINGING PERIODS FOR CONSENSUS BUILDING AMONG THE CONCERNED PARTIES.

- THE STUDY SHOWS:
  - AVAILABLE MARKET IN JAPAN AT PROJECT COMPLETION IS INSUFFICIENT FOR THIS LARGE SCALE PROJECT AND ADDITIONAL MARKET OUTSIDE JAPAN IS NEEDED FOR PROJECT SUCCESS.
  - BRIDGING SUPPLY IS NEEDED BEFORE 1998 TO PRESERVE THE AVAILABLE MARKET FOR AAGS.

2. PROJECT OUTLINE

%	MM$	%
15.5	GAS CONDITIONING 1,340	12.1
63.0	PIPELINE & COMPRESSOR STATIONS 5,440	49.4
21.5	LIQUEFACTION STORAGE & MARINE TERMINAL 1,860	17.0
	TOTAL= 8,640	
	LNG CARRIERS 2,370	21.5
	TOTAL=11,010	

2 TRAINS AT 9.2 MILLION TONS/YEAR
(1,160 MM SCFD)

TOTAL LENGTH = 1300KM
(800 MILES)
DIAMETER = 36 INCHES
PRESSURE = 156KG/CM^2
(2220 PSIG)

LIQUEFACTION
= 4 TRAINS AT 4.2 MM TONS/YEAR
(530 MM SCFD)

STORAGE
= 4 TANKS AT 127,200KL
(800,000 BBLS)
LOADING = 2 BERTHS

LNG CARRIERS
= 15 VESSELS OF 125,000KL
CARGO SPACE

PROJECT OUTLINE

- THE PROJECT CAPACITY IS PLANNED AT 14,000,000 TONS ANNUALLY IN TERMS OF LNG.
- HEATING VALUE OF GAS WILL BE TAILORED TO 10,430 KCAL/NM^3(1,110BTU/CF) TO MEET JAPANESE SPECIFICATION.
- OPERATING RESERVOIRS COULD PROVIDE UP TO 26 TCF OF GAS, SUFFICIENT FOR 35 YEAR SUPPLY AT PROJECT CAPACITY. POTENTIAL RESERVES COULD EXTEND THE PROJECT LIFE SIGNIFICANTLY.
- MOST OF THE INFRA-STRUCTURE FOR PRODUCING AND GATHERING FEED GAS FROM OPERATING RESERVOIRS IS IN PLACE. COSTS ASSOCIATED WITH THIS INFRA-STRUCTURE ARE OUTSIDE THE SCOPE OF THIS STUDY.
- GAS CONDITIONING PLANT IS LOCATED ON THE NORTH SLOPE. THE GAS PIPELINE IS RUN PARALLEL WITH TAPS FOR MORE THAN 80 PERCENT OF THE TOTAL DISTANCE AND LNG FACILITIES ARE LOCATED AT ANDERSON BAY NEAR TAPS VALDEZ TERMINAL.

3. TIME SCHEDULE

		PHASE I	- PRELIMINARY FEASIBILITY STUDY NOW COMPLETE
0TH			
	2	BRIDGING I	- COORDINATION FOR ENTRY INTO PHASE II
2TH			
	3	PHASE II	- BASIC DESIGN & ENGINEERING
5TH			
	1	BRIDGING II	- COORDINATION FOR ENTRY INTO PHASE III
6TH			
	5	PHASE III	- DETAIL DESIGN & CONSTRUCTION
11TH		PROJECT COMES ON LINE	

TIME SCHEDULE

- IT WILL TAKE 11 YEARS TO COMPLETE THE PROJECT AFTER COMPLETION OF THE PRELIMINARY FEASIBILITY STUDY NOW COMPLETE. THIS PERIOD COULD BE LONGER OR SHORTER DEPENDING ON STUDIES AND COORDINATIONS REQUIRED FOR DECISION MAKING.

- IN THE PERIOD OF BRIDGING I,

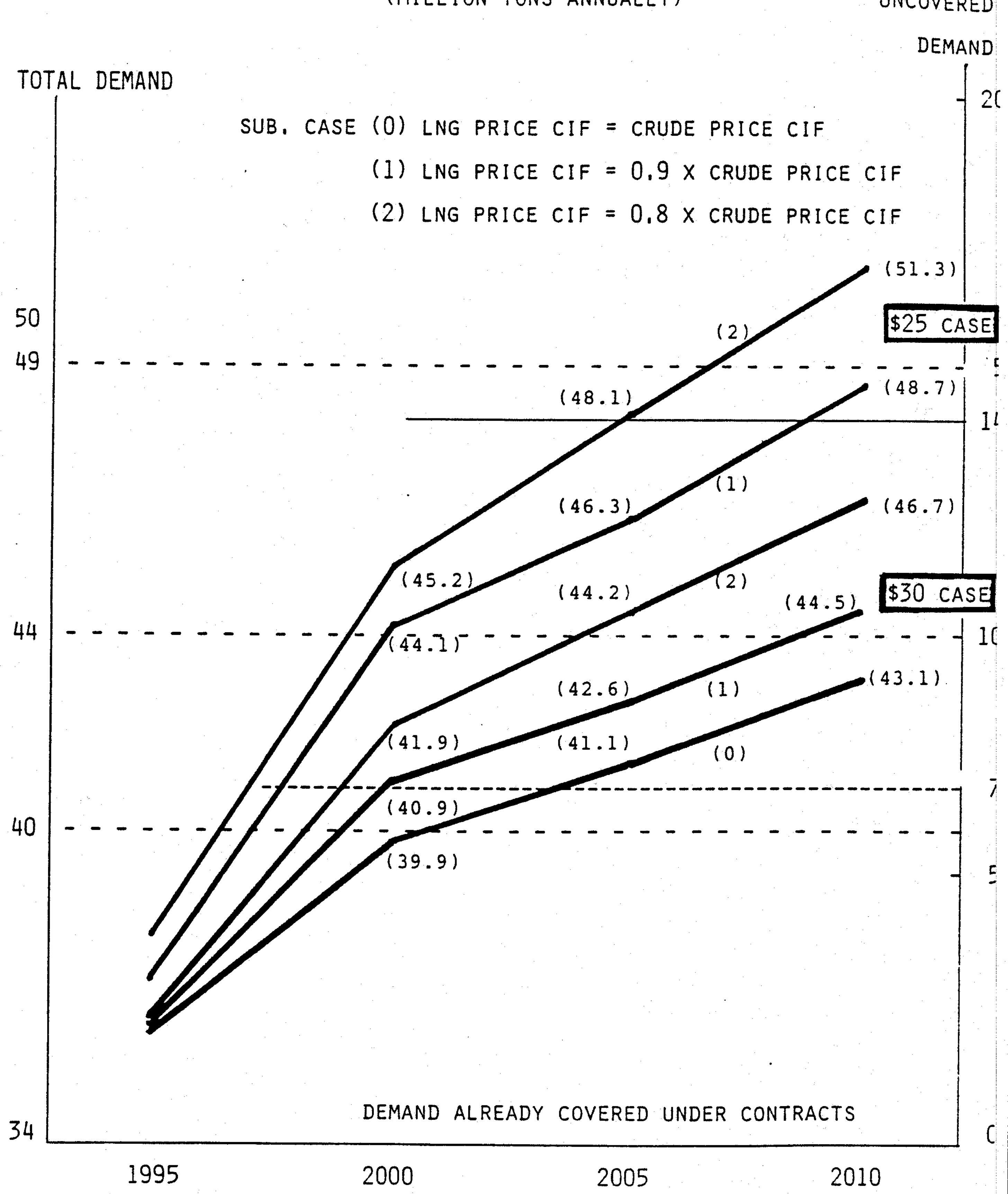
  A) JAPAN TO ESTABLISH A CONSENSUS FOR WHETHER OR NOT TO PURCHASE LNG IF CONDITIONS ARE SATISFIED IN THE FUTURE.
  B) U.S. TO ESTABLISH A CONSENSUS FOR WHETHER OR NOT TO EXPORT LNG IF CONDITIONS ARE SATISFIED IN THE FUTURE.
  C) CONSENSUS MAKING FOR HOW TO FORM RESPONSIBLE ORGANIZATIONS.
  D) ASSESSMENT AND DECISION ON EXPENDITURES REQUIRED FOR PHASE II. (JAPAN, U.S.)

- IN THE PERIOD OF BRIDGING II,

  A) THE U.S. AND JAPANESE PARTIES TO ENTER INTO A SELL/PURCHASE CONTRACT.
  B) THE U.S. AND JAPANESE PARTIES TO FORM RESPONSIBLE COMPANIES.
  C) THE U.S. AND JAPANESE PARTIES TO MAKE DECISION ON THE TOTAL INVESTMENTS.

4. LNG DEMAND IN JAPAN

(MILLION TONS ANNUALLY)



LNG DEMAND IN JAPAN

- MAJOR ASSUMPTIONS

  (1) ECONOMIC GROWTH - 3.1% ANNUALLY FOR 1985-2000
  2.5% ANNUALLY FOR 2000-2010

  (2) INDUSTRIAL STRUCTURE - CHANGING

  (3) CRUDE OIL PRICE (REAL PRICE, FOB)

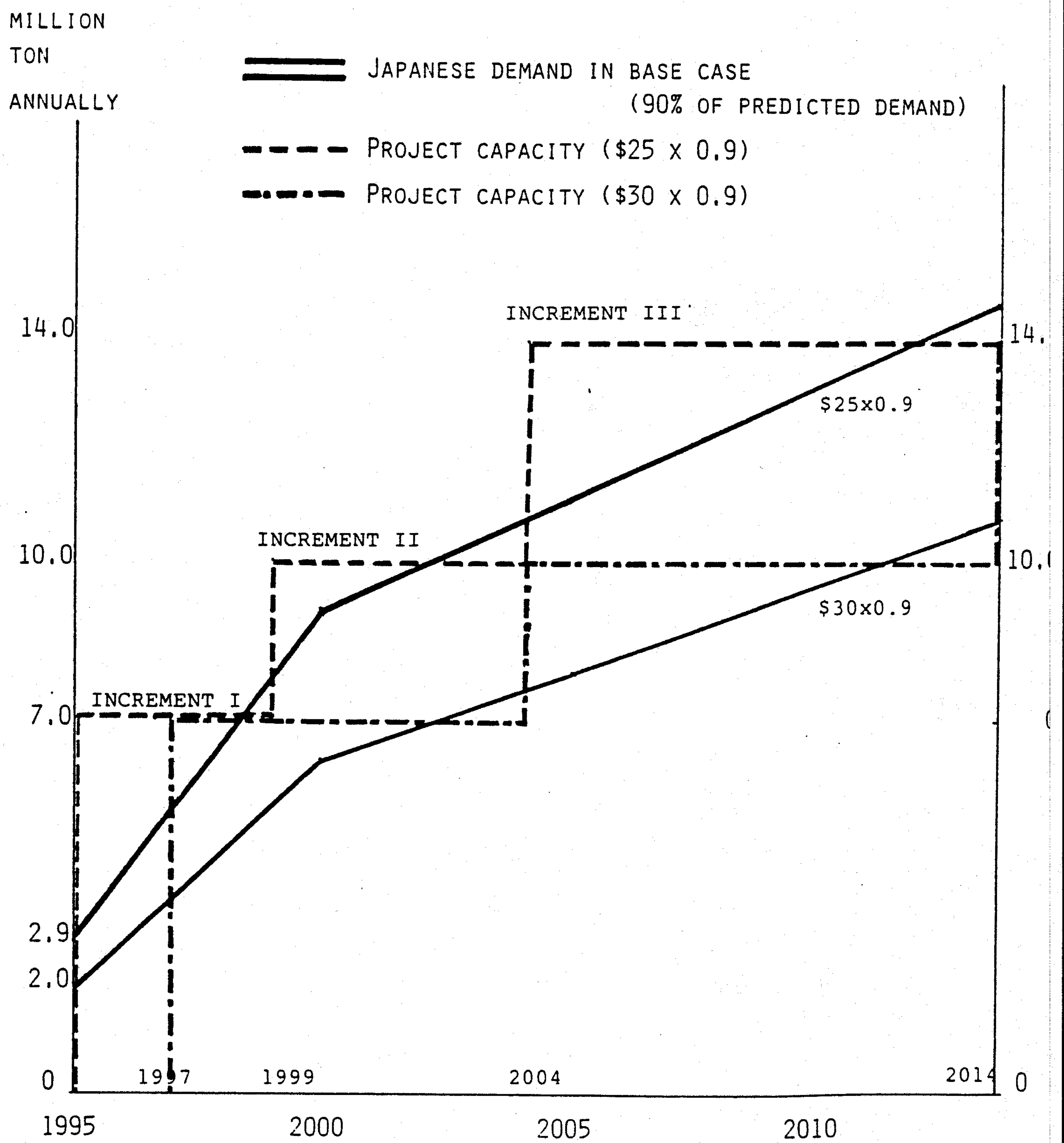
	1986	2000	2010
$25 CASE	15	25	30
$30 CASE	17	30	40

  (4) NUCLEAR POWER GENERATION CAPACITY IN 2000
  51 GW IN $25 CRUDE OIL PRICE CASE
  53 GW IN $30 CRUDE OIL PRICE CASE

- LNG DEMAND HAS BEEN PREDICTED USING IEE ECONOMETRIC MODEL THROUGH 2010 AND EXTENDED THROUGH 2030 BY A SCENARIO STUDY. DEMAND PREDICTED THEREABOVE HAS BEEN FURTHER ADJUSTED EXPECTING ADDITIONAL DEMAND OF CITY GAS IN NEW GEOGRAPHICAL AREAS.

- IN $30 CASE, LNG DEMAND REMAINING UNCOVERED WILL NOT REACH THE PROJECT CAPACITY OF 14 MILLION TONS ANNUALLY WITHIN 20 YEARS AFTER COMMENCEMENT OF OPERATION, IN EACH SUB-CASE OF LNG PRICE. EVEN IN $25 CASE, IT WILL TAKE 8-10 YEARS FOR THE UNCOVERED DEMAND TO REACH THE PROJECT CAPACITY.

5. PROJECT CONSTRUCTION SCHEDULE



PROJECT CONSTRUCTION SCHEDULE

- FUTURE DEMAND IN JAPAN WILL GRADUALLY INCREASE AS BRIEFED. IN AN ATTEMPT TO MATCH THIS GRADUAL BUILD-UP OF DEMAND, STEP-UP SCHEDULE OF THE PROJECT CAPACITY HAS BEEN CONSIDERED FOR ECONOMIC EVALUATION.

- IT HAS BEEN ASSUMED HEREIN THE AAGS SYSTEM COMES ON LINE WHEN THE OUTLET OF 3.5 MILLION TONS ANNUALLY IS SECURED, ALTHOUGH CONSTRUCTION PERIOD HAS BEEN ASSURED AT 11 YEARS IN "TIME SCHEDULE" SECTION.

- THE INITIAL CAPACITY HAS BEEN ASSUMED AT 7 MILLION TONS ANNUALLY (INCREMENT I CAPACITY) THEN EXPANDED TO 10.5 MILLION (INCREMENT II CAPACITY) AND 14.0 MILLION (INCREMENT III CAPACITY)

- THE INVESTMENT COST IN THE U.S. FACILITIES WILL INCREASE TO $9,000 MILLION FROM $8,640 MILLION ESTIMATED FOR ONE PACKAGE CASE.

INCREMENT I	$7,300 MILLION
INCREMENT II	$1,000 MILLION
INCREMENT III	$700 MILLION
TOTAL	$9,000 MILLION

- LARGE REDUCTION IN THE INITIAL INVESTMENT IS NOT POSSIBLE BECAUSE FULL SCALE INVESTMENT IN THE PIPELINE IS REQUIRED IN INCREMENT I.

	ACCEPTABLE LEVELS	LNG PRICE = $30 X 90%		LNG PRICE = $25 X 90%	
		BASE	POSITIVE	BASE	POSITIVE
* FROM THE COMMENCEMENT OF OPERATION					
FIRST YEAR TO RECORD PROFIT BEFORE TAX	6TH YEAR	11TH	9TH	11TH	9TH
FIRST YEAR TO WIPE OFF ACCUMULATED LOSS	10TH YEAR	18TH	16TH	19TH	16TH
NECESSITY OF CASH-DEFICIENCY FUND	UNNECESSARY	NECESSARY		NECESSARY	
* 20 YEARS FROM THE COMMENCEMENT OF OPERATION					
IRR ON TOTAL INVESTMENT COSTS (BEFORE TAX)	9.5%	8.3%	9.3%	8.0%	9.1%
IRR ON EQUITY (BEFORE TAX)	14%	5.5%	8.3%	3.7%	7.1%
* 20 YEARS FROM PLATEAU					
IRR ON TOTAL INVESTMENT COSTS (BEFORE TAX)	9.5%	10.6%	11.1%	9.7%	10.1%
IRR ON EQUITY	14%	11.2%	12.1%	9.3%	10.1%

PROJECT ECONOMICS

- PROJECT ECONOMICS HAS BEEN EVALUATED FOR THE CASES OF LNG DEMAND PREDICTED UNDER DIFFERENT LNG PRICES ASSUMED AT 90 AND 80 PERCENT CRUDE PARITY (FOR BOTH $30 AND $25 CASES). FEED GAS COST IS HEREIN ASSUMED AT 10-20 PERCENT OF LNG PRICE, CIF.

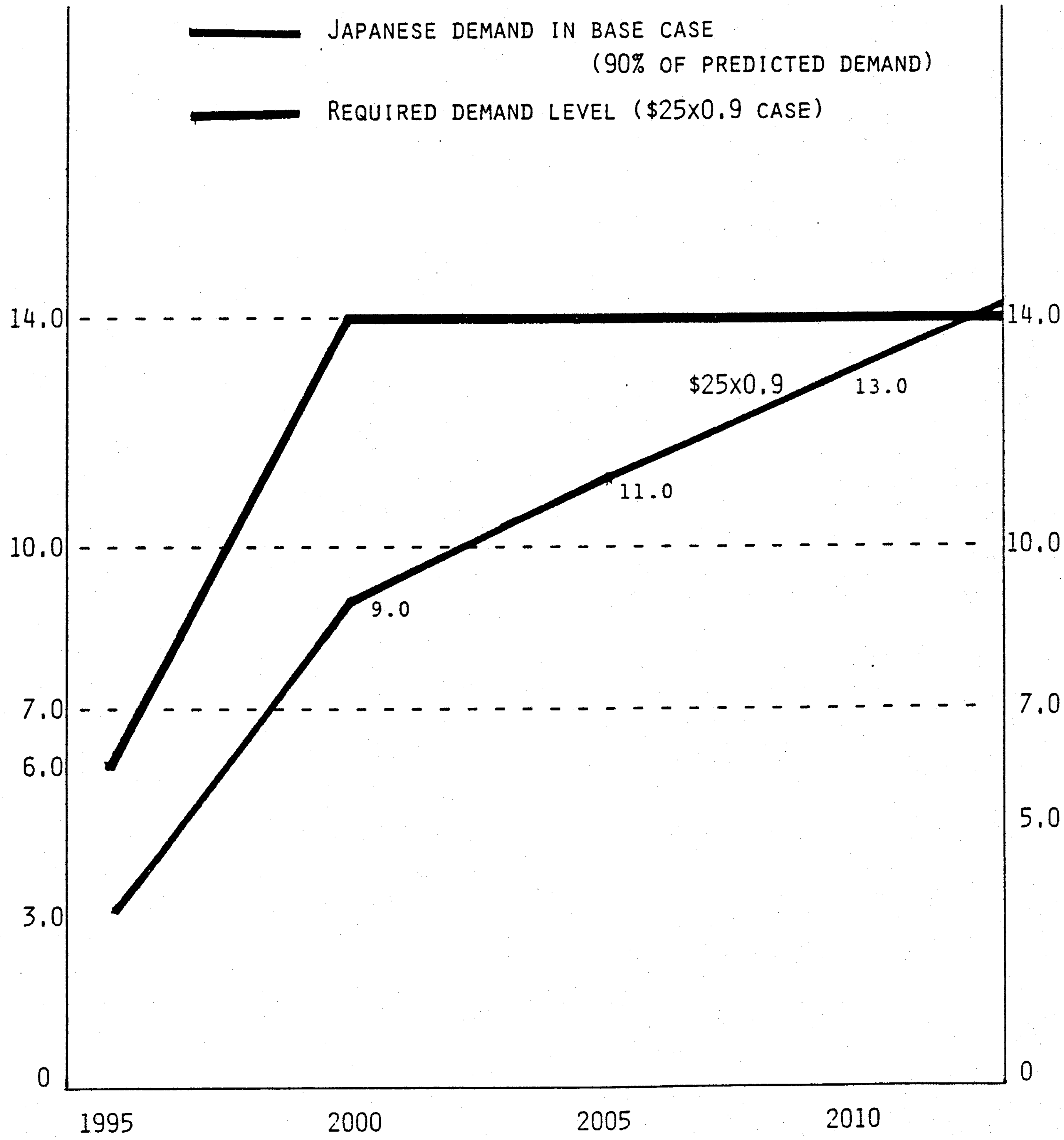
- THE OUTLET FOR THIS PROJECT HAS BEEN ASSUMED AT 90 PERCENT OF THE PREDICTED LNG DEMAND IN THE BASE CASES, AND 110 PERCENT IN THE POSITIVE CASES RUN FOR REFERENCE.

- THE METHODOLOGY USED HEREIN FOR ECONOMIC EVALUATION IS "WITHOUT ESCALATION". INTEREST RATE HAS BEEN ASSUMED AT 9.5 PERCENT ANNUALLY AS THE REAL RATE.

- AS SHOWN IN THE TABLE, THE HURDLES FOR PROJECT ECONOMICS EVALUATION HAVE NOT BEEN CLEARED IN EVERY RESPECT IN EVERY CASE, AS FAR AS THE LNG OUTLET IS SOUGHT FOR ONLY IN THE JAPANESE MARKET.

- LARGER DEMAND CREATED BY FURTHER PRICE DISCOUNT DOES NOT MAKE UP RESULTANT REDUCTION OF SALES REVENUE. SOME IMPROVEMENTS ARE SHOWN IN THE POSITIVE CASES BUT STILL UNDER THE ACCEPTABLE LEVELS.

7. LNG DEMAND REQUIRED TO JUSTIFY PROJECT ECONOMICS (IN MILLION TON ANNUALLY)



LNG DEMAND REQUIRED TO JUSTIFY PROJECT ECONOMICS

- MAGNITUDE OF INCREMENTAL LNG DEMAND IN JAPAN AND SLOW GROWTH THEREOF DO NOT JUSTIFY INVESTMENT IN A LARGE SCALE PROJECT SUCH AS THIS ONE.

- IN ORDER FOR THIS PROJECT TO BE ECONOMICALLY VIABLE INCREMENTAL DEMAND OUTSIDE JAPAN IS NEEDED IN ADDITION TO THE DEMAND LEVELS PREDICTED HEREIN FOR JAPAN, TOGETHER WITH BRIDGING SUPPLY TO PRESERVE LNG DEMAND BEFORE THE PROJECT COMES ON LINE.

- TRIAL CALCULATIONS INDICATE THAT SUCH INCREMENTS ARE IN AN ORDER OF THREE MILLION TONS AT THE TIME OF THE PROJECT COMPLETION INCREASING TO FIVE MILLION TONS WITHIN SIX YEARS.

- THE INCREMENTAL DEMAND, IF SECURED, MAKES THE PROJECT ECONOMICALLY FEASIBLE IN THE BASE CASE AT $25 X 0.9 PRICE, SATISFYING ALL THE YARDSTICKS FOR ECONOMIC EVALUATION ESTABLISHED FOR THIS STUDY, THOUGH MARGINALLY. THE PROJECT ECONOMICS SHOULD LOOK BETTER IN THE $30 X 0.9 PRICE CASE.

II DISCUSSION

1. The Basic Nature of This Study

1.1 The AAGS Project has been planned assuming delivery of natural gas existing in the North Slope area in the State of Alaska through a 1,300 km (800miles) pipeline system to South Alaska and liquefaction of the natural gas there for sale in Japan and other Far Eastern markets.

1.2 This study has been conducted on the basis of the STUDY AGREEMENT concluded between the U.S. and Japanese parties which provides, among all, the following understanding;

1.2.1 The purpose is solely to conduct a pre-feasibility study to develop initial, conceptual evaluations of the project.

1.2.2 Participation in the study by either party will not imply a commitment by either party for the purchase or sale of LNG or for conducting a feasibility study of the Project.

1.2.3 LNG demand predicted in this study covers only that of domestic demand in Japan.

1.3 LNG demand in Korea and Taiwan has been simultaneously surveyed on a preliminary basis by the U.S. side and the results of the U.S. survey will be integrated with LNG demand predicted in this study for Japan.

1.4 The U.S. side will be responsible for coordinating the review of this study as appropriate and seek input from natural gas suppliers during the consensus building period.

2. Progress Made

Meeting	Date	Achievements
a) Kick-Off	July'85	Time schedule, staffing and organization for study.
b) 2nd M.S.	Sep.'85	Direction of facility study; Basis of LNG demand forecast and economic analysis.
c) 3rd M.S.	Jan.'86	Interim report on Demand Forecast; Method of economic analysis, presumptions for test-run of computer models; Presumptions for conceptual designs of Alaskan & Japanese facilities.
d) 4th M.S.	Apr.'86	Interim report on Demand forecast and discussions on a success scenario; Interim report on the conceptual design of Alaskan facilities and discussions thereof; Discussions on the conceptual design of the Japanese facilities.
e) Facility Group Meeting	July'86	Presentation/discussion of Bechtel study; Report on gas reserve; Screening of presumptions for a success scenario.
f) 5th M.S.	Sep.'86	Presentation/discussion of demand forecast; Screening of cases for further analysis; Integration of demand forecast and economic analysis.
g) 6th M.S.	Feb.'87	Integration of the study results and discussion on the outline of the draft report.
h) Executive Committee Meeting	May '87	Final joint report (draft)

3. Outcome of Technical Study

3.1 Basis of the Project

a) LNG Supply - 14 million tons annually as the base case (maximum capacity - Technically Achievable)

b) Gas Reserve

Producing Reservoirs	- 26 TCF
Potential	- 70 TCF approx.

c) Heating Value of the LNG product - 10,430 Kcal/Nm^3 (1,110 BTU/CF)

3.2 Planned Facilities

a)	Gathering	- Existing
b)	Conditioning	- 2 trans at 9.2 million tons/year (1160 MM SCFD)
c)	Pipeline	- 1 X 36 inches for 1,300 KM,(800 miles) all buried, 156 KG/cm^2g (2220 psig)
d)	Liquefaction	- 4 trans at 4.2 million tons/year (530 MM SCFD)
e)	Storage	- 4 tanks at 127,200 kl (800,000Bbl), 5.3 days supply, with site secured for additional 4 tanks.
f)	Loading	- 2 berths
g)	LNG carriers	- 15 vessels of 125,000 Kl cargo space.

3.3 Investment Cost Estimated (in January 1986 U.S. dollar)

a)	Additional well development/gas gathering	- (outside the scope of this stu
b)	Conditioning	- $1,340 MM
c)	Pipeline	- $5,440 MM
d)	Liquefaction	
e)	Storage/Loading	- $1,860 MM
	Sub. Total	$8,640 MM
f)	LNG carriers	- $2,370
	(Freight cost	- ¢64.77/MMBTU or $33.28/T)
	Total	$11,010 MM

g) Receiving Terminal

Power generation plant type (2000MW) - $530MM

Town Gas Type (1MM T/Y) - $410MM

3.4 Construction Period (the standard case)

Following are the probable time lengths required for each phase and bridging, after completion of phase I which is the prefeasibility study now complete.

a) Coordination for entry into Phase II *(1) -- 2 years (assumed)

b) Phase II (Basic Design & F/S) -- 3 years

c) Coordination for entry into Phase III *(2) -- 1 year (assumed)

d) Phase III (Detail Design & Construction) -- 5 years

(Total: 11 years is the standard case. The period could be longer or shorter depending on studies and coordinations required for decision making.)

*(1) a) Japan to establish a consensus for whether or not to purchase LNG if conditions are satisfied in the future.

b) U.S. to establish a consensus for whether or not to export LNG if conditions are satisfied in the future.

c) Consensus making for how to form responsible organizations

d) Assessment and decision on expenditures required for Phase II. (Japan, U.S.)

*(2) a) To enter into a sell/purchase contract. (Japan, U.S.)

b) Formation of responsible companies. (Japan, U.S.)

c) Decision on the total investments. (Japan, U.S.)

4. LNG Demand Forecast

4.1 Objective

To predict LNG demand in Japan for the concerned period and to assess conditions on which the Alaskan LNG can penetrate into the Japanese market.

4.2 Methods for demand forecast

a) Econometric Model (consisting of macro economic model, industry relation model and energy demand-supply model) developed by IEE for 1985-2010.

b) Scenario study using a simplified model for 2010-2030.

c) Potential LNG demand that has been created by new technologies and new consuming areas has been studied independently from the economic model study.

4.3 Results from the econometric model study for 1985-2010

4.3.1 Presumptions for demand forecast

The presumptions include IEE's view on, among all, changes in economic-industrial structures and living mode that will be caused by external elements such as appreciation of the Japanese currency, trade frictions and devaluated oil price. Also included therein are IEE's view on energy sources for power generation, new mode of power generation, new energy sources and broader application of co-generation system. The main presumptions are summarized below.

i) Real economic growth
3.1% annually for 2000/1985
2.5% annually for 2010/2000

Yen will keep its appreciation supported by continuing trade surplus. Export will level off due to trade frictions and yen appreciation; and economic growth will be supported by domestic demand that will not be sufficient for higher growth.

ii) Industrial Structure - Substantially changing

Japan's fundamental industry producing base materials will be scaled down to the level of its domestic demand because of increased import and decreased export. Crude steel production, for example, will decrease to 75 million tons in 2000 and 43 million tons in 2010 from 100 million tons in 1985.

iii) Other presumptions

Cases for screening are produced by combinations of the assumptions set below. Since it is considered that sufficient LNG demand will not exist in Japan if price is assumed at the crude oil parity, potential expansion of LNG demand is examined herein by discounting LNG price.

. LNG price (Real price, CIF)

100% crude price
90% "
80% "

. Oil price (Real price, FOB), $/BBL

	1986	2000	2010
$25 CASE	15	25	30
$30 CASE	17	30	40

. Coal price (Real price, CIF), $/Ton

1986 - 42

1990 - 46

2000 - 54

. Nuclear power generation capacity in 2000

51 GW in $25 crude oil price case

53 GW in $30 crude oil price case

4.3.2 Demand predicted through IEE Econometric Model

	$30 CASE			$25 CASE		
LNG Price	100%	90%	80%	100%	90%	80%
1995	35.9	35.9	36.0	36.7	36.8	37.6
2000	39.5	40.3	41.1	41.8	43.3	44.1
2005	40.8	41.8	43.3	43.5	45.3	46.9
2010	42.3	43.6	45.6	45.3	47.6	50.0

(LNG Demand in MMT/Y)

Please refer the attachments for details.

4.4 Results from 2030 scenario study

Three scenarios, conventional scenario, oil boom scenario and gas boom scenario, have been drawn on the basis of predictions obtained from the computer study for 2000. All these scenarios indicate that LNG demand in 2030 will exceed that in 2010.

4.5 Potential demand of LNG in new geographical areas

Potential demand of LNG for supply of city gas in new geographical areas has been predicted through competitiveness analysis. Japan is divided into 11 blocks in the model which has 4 sub. models classifying the potential markets by population in the city areas, gas (LPG) demand, access to gas pipeline system. LNG is picked up where it is competitive at given LNG price and demand elasticity to the price of gas. Demand predicted herein as summarized below is the potential demand in addition to the demand predicted in 4.3.

	$30 CASE			$25 CASE	
	100%	90%	80%	90%	80%
1995	280	330	390	460	510
2000	400	600	790	880	1,050
2005	610	780	940	1,030	1,150
2010	820	930	1,040	1,190	1,270

(in 1,000 tons annually)

4.6 Estimated total LNG demand in Japan

	$30 CASE			$25 CASE	
	100%	90%	80%	90%	80%
1995	36.2	36.3	36.4	37.2	38.1
2000	39.9	40.9	41.9	44.1	45.2
2005	41.4	42.6	44.2	46.3	48.1
2010	43.1	44.6	46.7	48.7	51.3

(LNG Demand in MM/T/Y)

LNG demand & nuclear capacity predicted for 2000 by the others

	LNG, MM T/Y	Nuclear, GW
MITI*	41.5	62
E. P. Association	25.0-30.0	54-59
	(for power generation only)	
	(36.0-41.0)**	
Gas Association	42.3	59
P.A.J.	34.6	53

* Per 1983 Long Range Plan and changes in economic environment thereafter not reflected.

** Added by 1,100MT/Y predicted by IEE for city gas demand.

Note: It is estimated that LNG price is assumed at the crude oil parity in those predictions.

5. A screening study for economic feasibility

A screening study for economic feasibility was conducted for 72 cases based on combinations of assumptions. The assumptions were (1) LNG price herein assumed at 100%, 90% and 80% of crude oil energy parity, (2) feed gas cost herein assumed at 0% to 20% of LNG price CIF Japan, (3) LNG supply assumed herein at full capacity supply from the commencement of operation and (4) the capital cost for the four cases as shown below.

Annual Capacity in Million Tons	Capacity Cost in Billion Dollars
14.0	8.6
10.5	7.5
7.0	6.0
7.0 then 14.0	8.9

Based on these screening studies, cases for integrated analysis were narrowed as follows:

1) LNG price at 90% and 80% of crude oil energy parity
2) Feed gas cost at 10% of LNG price CIF Japan
3) LNG supply to match the forecast in section 4
4) Design concept to be:

   a) Full scale 14 mm tons/yr capacity
   b) Phased build up design

The case of 10.5 million ton annual capacity is economically feasible, depending on LNG price assumed, if the outlet is secured facilitating full capacity operation right after the project completion. This case, however, was not included in the cases for integrated analysis because the Japanese LNG demand surveyed does not facilitate full capacity operation from the beginning.

The basic financial criteria used in the screening study and the integrated analysis described in section 6 are:

1) Interest rate on debt 9.5%

2) Debt Equity Ratio 75%/25%

3) Project Contract Life 20 years after commencement of operation

4) Internal Rate of Return on Total Investment
   9.5% -- Profitability yardstick

5) Internal Rate of Return on Equity
   14% -- Profitability yardstick

6) First year to record profit (before tax)
   within 6 years from the commencement of operation
   -- Bankability yardstick

7) First year to wipe off accumulated deficit within 10 years from the commencement of operation
   -- Bankability yardstick

8) All evaluations are performed without escalation

6. Integration Study

The studies made in the foregoing sections of 3 through 5 are integrated herein to predict the outlet for Alaskan LNG and to optimize the capacity of the project and the time of the project coming on line in light of the sales tonnage expected for each year.

6.1 Incremental LNG demand in Japan

6.1.1 LNG demand predicted through IEE's Econometric Model reflects (1) changes expected in the industrial structure, (2) growth in GNP and power demand and (3) nuclear capacity expansion, predicted in a manner and at levels generally accepted. Therefore, this forecast should be understood to be a reasonable prediction for use in this preliminary feasibility study of AAGS Project.

6.1.2 The IEE Econometric Model does not contain possible LNG demand expansion into local cities. This section has been examined separately as already briefed. Therefore, the total expected demand is a sum of demand forecast through the econometric model and this potential demand studied separately.

LNG Demand in 1995-2010
(in 1,000 tons annually)

Case	1995	2000	2010
$30x100%	36,200	39,900	43,100
90%	36,300	40,900	44,600
80%	36,400	41,900	46,700
$25x 90%	37,200	44,100	48,700
80%	38,100	45,200	51,300

(Ref. Table 1)

6.1.3 Incremental demand is the total expected demand minus supply under existing contracts. (Refer Table 1 attached)

6.2 Expected demand (outlet) of AAGS Project

6.2.1 The LNG demand has been predicted based on the assumptions that the price of LNG will fall down to 80-90% level of crude oil price. However, at the present time, the electric industry has a basic view that LNG price is high relative to the other energy sources for power generation and that "take or pay" clauses cause difficulty to cope with changing demand. Because of such basic view, the industry considers that the LNG share in the total energy package consumed for power generation has been already too high (21 percent at present). This basic view may not change until they have reasonable prospects for price reduction and improvement of the delivery clause.

6.2.2 Electric Power Development Plan has been considered firmed up through 1995. This plan includes 40GW LNG-fired plants operating in 1995. The industry's 21st Century Vision, recently published, does not specify power generation capacity of each energy source, but it is generally considered that LNG-fired capacity will level off after 1995..

IEE's forecast includes 38GW LNG-fired capacity in 1995, 2GW lower than the industry's plan, and 45GW in 2000, assuming that the total demand of LNG including that for city gas sector will grow at an average annual rate of 3.3 percent during 1995-2000, expecting improvement in price competitiveness of LNG.

In view of the lead time required to convert energy source in the existing plants (5 years) and to build grass-root LNG power plants (10 years), IEE's view could be optimistic unless the industry establishes a consensus at an early stage that LNG will become economically competitive as IEE presently considers. They will change their present plan or firm up new power development program after they had reasonable prospects for improvement in LNG competitiveness. The city gas industry also needs lead time to firm up expanded sales program.

6.2.3 In view of observations as briefed in 6.2.1 and 6.2.2 herein, LNG-fired capacity expansion may not be realized as IEE expects even if LNG price become competitive and the delivery terms are improved, at some stage in the future. Therefore, economic evaluation of AAGS Project should include some allowance for contingent delay in LNG off-take.

6.2.4 Potential LNG projects (such as Sakhalin project expected to supply 3 million tons annually) and potential LNG markets outside Japan (such as Korean market expected to consume 3.5 million tons annually) have not been covered in this study. Since such potential demand and supply contains so many elements unknown to us at this stage, these demand and supply have not been considered in this study.

6.2.5 LNG demand forecast herein, on the other side, could increase because of (1) potential delay in nuclear power construction due to difficulty in securing the future plant sites, (2) possible inability to extend the existing contracts due to gas reserve limitation, (3) fuel conversion at a faster pace from oil to LNG at the existing oil-fired power plants and (4) faster growth in LNG demand in the markets outside Japan such as Korea and Taiwan.

6.2.6 In view of elements discussed herein, two cases are considered in evaluating economics of the AAGS Project. One is the BASE CASE which is 90% of the LNG incremental demand forecast by IEE. The other case is the POSITIVE CASE that includes larger outlet, 110% of the incremental demand forecast by IEE. Outlet for the AAGS Project will be predicted for eight cases, therefore, with each demand case having two sub. cases.

Case	1	2	3	4
Oil price	30	30	25	25
LNG price	90%	80%	90%	80%

6.2.7 In 2030 scenario study, it is predicted that LNG demand in 2030 will not be less than that in 2010 in each scenario. In prediction of outlet for the AAGS project in 2030, it is assumed that LNG demand will grow for a period of 2010-2030 at the same average annual growth rate estimated for 2005-2010.

6.2.8 Expected outlet of AAGS Project in Japan is shown on Table 1 attached.

6.3 Features of LNG Demand Growth in Japan.

6.3.1 LNG demand above contracted supply is considered to be sensitive to the price as shown below.

Breakdown of
Incremental LNG Demand
(during 15 years of 1995/2010)
- in 1,000 tons -

	Electric Sector	City Gas Sector	Total
\$30 x 1.0	1,700	5,250	6,950
x 0.9	2,750	5,540	8,290
x 0.8	4,460	5,810	10,270
\$25 x 0.9	5,590	5,940	11,530
x 0.8	7,100	6,070	13,170

6.3.2 LNG demand in the city gas sector will increase linearily at an average annual pace of 350-400 thousand tons. Therefore, supply arrangement should be built up meeting such gradual demand growth.

6.3.3 LNG demand in the electric power sector will increase step-wise by 500-1,000 thousand tons annually, since incremental demand is created by new plants to be constructed and fuel conversion at the existing plants. Supply arrangement should be completed in time for the plant completion or modification.

6.3.4 In view of 6.3.2 and 6.3.3 herein above, it can not be expected that large demand for LNG will incrementally arise in time for the project completion. We consider it more reasonable to assume that LNG supply under this project will start with about 3.5 million tons annually and gradually increase at an annual pace of 1.0-1.5 million tons thereafter.

6.4 Capacity Step-up Schedule

Based on the magnitude of the outlet expected for the AAGS Project, timing of the first LNG delivery, annual tonnage delivered and system capacity required to meet demand have been defined. The schedule defined herein reflects estimated capital investment in each capacity case, results of the financial analysis so far obtained in the screening study and the experience accumulated in typical LNG projects.

There are critical relations between the LNG outlet expected at the time of the system completion, optimum initial capacity and construction schedule. Herein in this study, the initial capacity is set at 7 million tons annually. However, the AAGS system will come on line by the time of around 3.5 million tons of the outlet expected because Japan's LNG market allows stepwise increase of LNG supply within around 3.5 million tons.

6.4.1 LNG price - $30 x 0.9

a) Base Case

Capacity	MT/Y	7,000	10,500	14,000
Completion		1997	2004	2014
Outlet(at the time of completion)	MT/Y	3,600	7,400	10,900
Years required to reach capacity		6	10	8

b) Positive Case

Capacity	MT/Y	7,000	10,500	14,000
Completion		1996	2000	2008
Outlet(at the time of completion)	MT/Y	3,460	7,600	10,700
Years required to reach capacity		4	8	8

6.4.2 LNG price - $25 x 0.8

a) Base Case

Capacity	MT/Y	7,000	10,500	14,000
Completion		1995	1998	2002
Outlet(at the time of completion)	MT/Y	3,700	7,400	11,100
Years required to reach capacity		3	3	6

b) Positive Case

Capacity	MT/Y	7,000	10,500	14,000
Completion		1995	1997	2000
Outlet(at the time of completion)	MT/Y	4,500	7,500	12,300
Years required to reach capacity		2	2	4

It should be noted that the completion of the AAGS system in 1995-1997 is difficult if the 11 years of the probable construction period of the AAGS system is considered. Refer to figures 1-5 attached.

6.4.3 Capital cost for the 3-phased construction schedule is estimated as shown below:

Phase I (7 million ton p.a.):	US$7.3 billion
Phase II (10.5 million ton p.a.):	US$1.0 billion
Phase III(14.0 million ton p.a.):	US$0.7 billion
Total	US$9.0 billion

6.5 The Result of Economic Feasibility Study

a) Based on Japan's demand for ANS LNG, each of eight cases of three-phased construction is judged to be economically infeasible by both profitability and bankability yardstick. Why? The investment for each phase is always made in advance to its demand which is gradually building up. Therefore its supply capacity always exceeds its demand for each phase. (i.e. it takes a relatively long lead time for the demand to fill in the surplus capacity or to catch up the capacity for each phase.)

b) Although the price discount can create more sales volume in Japan than no discount (crude oil energy parity price), it makes the project less profitable because the augmented sales volume can not make up reduction of sales revenue resulting from the price discount. Namely, price is more decisive for profitability than volume. (N.B. Please compare IRR of 80% case with that of 90% case in the same price bracket.)

Without Escalation - Cases of 4 Phased Capacity (Feed Gas Cost: 10%)

	Acceptable Levels	$30 X 90%		$30 X 80%		$25 X 90%		$25 X 80%	
		Base	Positive	Base	Positive	Base	Positive	Base	Positive
From the commencement of operation									
First year to record profit before Tax	6th year	11th year	9th year	11th year	10th year	11th year	9th year	12th year	9th year
First year to wipe off accumulated loss	10th year	18th year	16th year	21th year	17th year	19th year	16th year	24th year	19th year
Necessity of cash-dificiency fund	unnecessary	necessary	necessary	necessary	necessary	necessary	necessary	necessary	necessary
20 years from the commencement of operation									
IRR on total investment costs (before tax)	9.5%	8.3%	9.3%	7.1%	8.6%	8.0%	9.1%	6.7%	7.8%
IRR on Equity (before tax)	14%	5.5%	8.3%	-	6.6%	3.7%	7.8%	-	3.6%
20 years from plateau									
IRR on total investment costs (before tax)	9.5%	10.6%	11.1%	9.5%	10.1%	9.7%	10.1%	8.3%	8.9%
IRR on Equity	14%	11.2%	12.1%	9.0%	10.2%	9.3%	10.1%	5.2%	7.4%

7. Summary & Preliminary Conclusions

7.1 Gas Reserve

7.1.1 Vast natural gas reserve exists in the North Slope area that is sufficient to supply LNG for 35 years at an annual pace of 14 million tons out of operating reservoirs. When inferred reserve is included, the total reserve is considered to be sufficient to supply LNG at the same annual pace for approximately 100 years.

7.1.2 Wells and gathering system of natural gas have been already constructed for the operating reservoirs. Therefore, additional investment cost for delivery of natural gas to the transfer point should be low.

Note: Price of natural gas to the transfer point has been assumed in a range of 5-20% of LNG CIF price in this pre. feasibility study, because the U.S. side was not in a position to quote the price at this stage. This should be quoted in an early stage of the coordination period for phase II.

7.2 LNG demand forecast

7.2.1 LNG demand is considered to be sensitive to the price as shown in section 6.3.1.

7.2.2 It can not be expected that large demand of LNG will stepwise arise in time for the project completion. We consider it more reasonable to assume that Japanese LNG demand under this project will start with about 3.5 million tons annually and gradually increase at an annual pace of 1.0-1.5 million tons thereafter.

7.2.3 As reviewed, the city gas sector is expected to create substantial part of the incremental LNG demand. If it is assumed that such incremental LNG demand by the city gas sector is fully covered by supply from the AAGS Project, the North Slope gas will have about 30 percent share of the total feed gas supply to the city gas sector. They can not replace LNG for alternative feedstock in case where supply is interrupted due to troubles caused to the system. The electric sector is also concerned about such contingency. In order to eliminate such concern and as a mean to improve supply security, further study during the consensus building period will be required in the following aspects;

a) The upper limit of Alaskan LNG share that will be acceptable to the consumers in light of supply security and LNG demand size in Japan (predicted at 40-45 million tons annually in 2000).
b) General review of the technical reliability of LNG deliverability through the AAGS project.

7.3 Technical feasibility

7.3.1 It is technically feasible to construct a system capable to supply 14 million tons of LNG annually.

7.3.2 The total length of period required to complete the project will be 11 years in the standard case.

7.4 Revision of the project concept

7.4.1 It is considered that it will be in 1995 ($25x0.8 case) - 1997($30x1.0 case) when potential demand in Japan for the Alaskan LNG reaches to 3.5

million tons annually as shown in Fig. 1-5 attached herewith. In view of the construction period required (11 years in the standard case as already discussed), it is not practical to expect the project will become ready to meet such demand in time.

7.4.2 The project concept assuming the initial capacity at 7 million tons annually and the ultimate capacity at 14 million tons annually does not meet the Japan's LNG market requirement in the following aspects, unless LNG demand in the other markets is taken into consideration;

a) It is not practical to expect an outlet in Japan to accommodate 7 million tons from the first year since demand will grow just gradually.

b) The project based on Japanese demand does not look economically viable since it takes many years to reach the full capacity supply at 14 million tons annually.

c) Reliance on one pipeline system for large share of LNG supply does not resolve the consumers concern on supply security even if contingency of supply interruption could be reduced technically.

7.4.3 In view of 7.4.1 and 7.4.2 herein, time schedule of the project (the initial capacity and step-up expansion to the ultimate capacity) may not be reasonably programmed, if the scope of the market is limited to that in Japan. The other potential markets in the Far East including Korea and Taiwan need to be integrated.

7.5 Analysis of the project economics

The final analysis of the project economics will be conducted on the basis of the project schedule made in consideration of the total LNG demand in the Far East and on the basis of assumptions fine-tuned for financial analysis.

Supply/Demand Forecasts for LNG in Japan (1,000ton)

Table 1 (1/3)

Crude Oil Price in 2000 : $30
LNG Price Parity : 100%

YEAR	DEMAND * Power Generation	City Gas	Others	Total 2000 Model	Potential Demand in Local Cities	Estimated Total Demand in Japan (A)	Supply Contracted (B)	Estimated New Demand (C=A-B)	Expected New LNG Demand in Japan: Base Case (D=Cx0.9)	Expected New LNG Demand in Japan: Positive Case (E=Cx1.1)
1995	26,393	9,147	350	35,890	280	36,170	34,000	2,170	1,953	2,387
1996	26,769	9,453	350	36,572	300	36,872	34,000	2,872	2,585	3,159
1997	27,150	9,769	350	37,269	330	37,599	34,000	3,599	3,239	3,959
1998	27,536	10,096	350	37,982	350	38,332	34,000	4,332	3,899	4,765
1999	27,928	10,433	350	38,711	380	39,091	34,000	5,091	4,582	5,600
2000	28,326	10,782	350	39,458	400	39,858	34,000	5,858	5,272	6,444
2001	28,302	11,056	350	39,708	440	40,148	34,000	6,148	5,533	6,763
2002	28,278	11,337	350	39,965	480	40,445	34,000	6,445	5,801	7,090
2003	28,255	11,626	350	40,231	530	40,761	34,000	6,761	6,085	7,437
2004	28,231	11,921	350	40,502	570	41,072	34,000	7,072	6,365	7,779
2005	28,207	12,225	350	40,782	610	41,392	34,000	7,392	6,653	8,131
2006	28,184	12,535	350	41,069	650	41,719	34,000	7,719	6,947	8,491
2007	28,160	12,854	350	41,364	690	42,054	34,000	8,054	7,249	8,859
2008	28,136	13,181	350	41,667	740	42,407	34,000	8,407	7,566	9,249
2009	28,113	13,516	350	41,979	780	42,759	34,000	8,759	7,883	9,635
2010	28,089	13,860	350	42,299	820	43,119	34,000	9,119	8,207	10,031

Supply/Demand Forecasts for LNG in Japan (1,000ton)

Table 1 (2/3)

Crude Oil Price in 2000 : $30
LNG Price Parity : 90%

YEAR	DEMAND * Power Generation	City Gas	Others	Total 2000 Model	Potential Demand in Local Cities	Estimated Total Demand in Japan (A)	Supply Contracted (B)	Estimated New Demand (C=A-B)	Expected New LNG Demand in Japan: Base Case (D=Cx0.9)	Expected New LNG Demand in Japan: Positive Case (E=Cx1.1)
1995	26,393	9,198	350	35,941	330	36,271	34,000	2,271	2,044	2,498
1996	26,891	9,523	350	36,764	380	37,144	34,000	3,144	2,830	3,458
1997	27,398	9,859	350	37,607	430	38,037	34,000	4,037	3,633	4,441
1998	27,916	10,208	350	38,474	480	38,954	34,000	4,954	4,459	5,449
1999	28,442	10,569	350	39,361	540	39,901	34,000	5,901	5,311	6,491
2000	28,979	10,942	350	40,271	600	40,871	34,000	6,871	6,184	7,558
2001	28,995	11,226	350	40,571	640	41,211	34,000	7,211	6,490	7,932
2002	29,011	11,517	350	40,878	670	41,548	34,000	7,548	6,793	8,303
2003	29,027	11,816	350	41,193	710	41,903	34,000	7,903	7,113	8,693
2004	29,043	12,123	350	41,516	750	42,266	34,000	8,266	7,439	9,093
2005	29,059	12,437	350	41,846	780	42,626	34,000	8,626	7,763	9,489
2006	29,075	12,760	350	42,185	810	42,995	34,000	8,995	8,096	9,895
2007	29,091	13,091	350	42,532	840	43,372	34,000	9,372	8,435	10,309
2008	29,107	13,431	350	42,888	870	43,758	34,000	9,758	8,782	10,734
2009	29,123	13,779	350	43,252	900	44,152	34,000	10,152	9,137	11,167
2010	29,139	14,137	350	43,626	930	44,556	34,000	10,556	9,500	11,612

Crude Oil Price in 2000 : $30
LNG Price Parity : 80%

1995	26,393	9,270	350	36,013	390	36,403	34,000	2,403	2,163	2,643
1996	27,001	9,613	350	36,964	470	37,434	34,000	3,434	3,091	3,777
1997	27,643	9,969	350	37,962	550	38,512	34,000	4,512	4,061	4,963
1998	28,291	10,338	350	38,979	630	39,609	34,000	5,609	5,048	6,170
1999	28,953	10,720	350	40,023	710	40,733	34,000	6,733	6,060	7,406
2000	29,631	11,117	350	41,098	790	41,888	34,000	7,888	7,099	8,677
2001	29,751	11,410	350	41,511	820	42,331	34,000	8,331	7,498	9,164
2002	29,871	11,712	350	41,933	850	42,783	34,000	8,783	7,905	9,661
2003	29,992	12,021	350	42,363	880	43,243	34,000	9,243	8,319	10,167
2004	30,114	12,338	350	42,802	910	43,712	34,000	9,712	8,741	10,683
2005	30,236	12,664	350	43,250	940	44,190	34,000	10,190	9,171	11,209
2006	30,358	12,998	350	43,706	960	44,666	34,000	10,666	9,599	11,733
2007	30,481	13,341	350	44,172	980	45,152	34,000	11,152	10,037	12,267
2008	30,605	13,693	350	44,648	1,000	45,648	34,000	11,648	10,483	12,813
2009	30,729	14,055	350	45,134	1,020	46,154	34,000	12,154	10,939	13,369
2010	30,853	14,426	350	45,629	1,040	46,669	34,000	12,669	11,402	13,936

* : Include LNG demand for Fuel Cells (1995 ; 473, 2000 ; 924, 2010 ; 1,932)

Supply/Demand Forecasts for LNG in Japan (1,000ton)

Table (3/3)

Crude Oil Price in 2000 : $25
LNG Price Parity : 90%

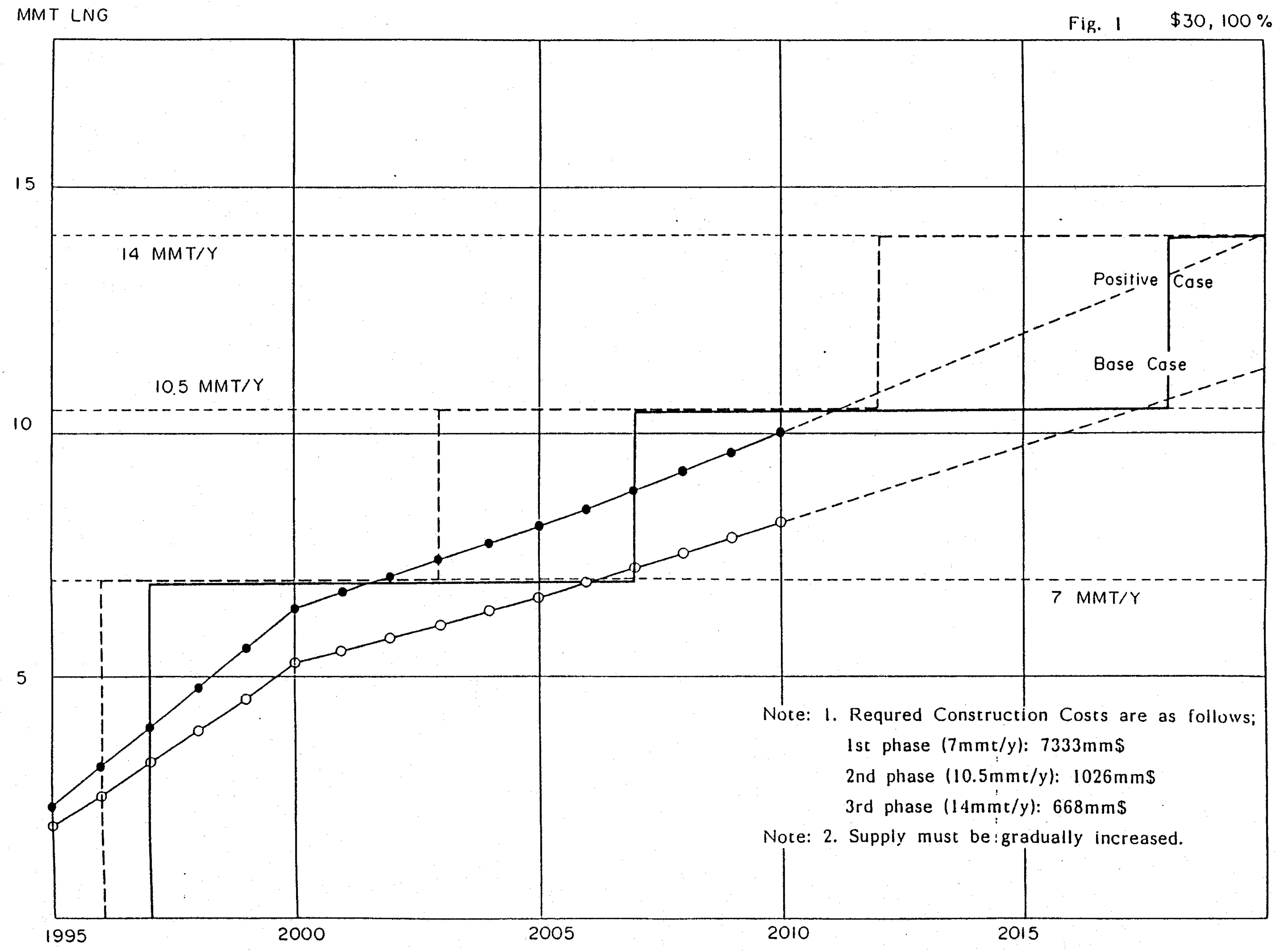
YEAR	DEMAND * Power Generation	City Gas	Others	Total 2000 Model	Potential Demand in Local Cities	Estimated Total Demand in Japan (A)	Supply Contracted (B)	Estimated New Demand (C=A-B)	Expected New LNG Demand in Japan: Base Case (D=Cx0.9)	Expected New LNG Demand in Japan: Positive Case (E=Cx1.1)
1995	26,957	9,444	350	36,751	460	37,211	34,000	3,211	2,890	3,532
1996	27,831	9,787	350	37,968	540	38,508	34,000	4,508	4,057	4,959
1997	28,733	10,143	350	39,226	620	39,846	34,000	5,846	5,261	6,431
1998	29,665	10,512	350	40,527	700	41,227	34,000	7,227	6,504	7,950
1999	30,626	10,895	350	41,871	790	42,661	34,000	8,661	7,795	9,527
2000	31,619	11,291	350	43,260	880	44,140	34,000	10,140	9,126	11,154
2001	31,711	11,589	350	43,650	910	44,560	34,000	10,560	9,504	11,616
2002	31,803	11,895	350	44,048	940	44,988	34,000	10,988	9,889	12,086
2003	31,895	12,209	350	44,454	970	45,424	34,000	11,424	10,281	12,566
2004	31,987	12,531	350	44,868	1,000	45,868	34,000	11,868	10,682	13,055
2005	32,080	12,862	350	45,292	1,030	46,322	34,000	12,322	11,090	13,554
2006	32,173	13,202	350	45,725	1,060	46,785	34,000	12,785	11,507	14,064
2007	32,266	13,550	350	46,166	1,100	47,266	34,000	13,266	11,940	14,593
2008	32,360	13,908	350	46,618	1,130	47,748	34,000	13,748	12,373	15,123
2009	32,454	14,275	350	47,079	1,160	48,239	34,000	14,239	12,815	15,663
2010	32,548	14,652	350	47,550	1,190	48,740	34,000	14,740	13,266	16,214

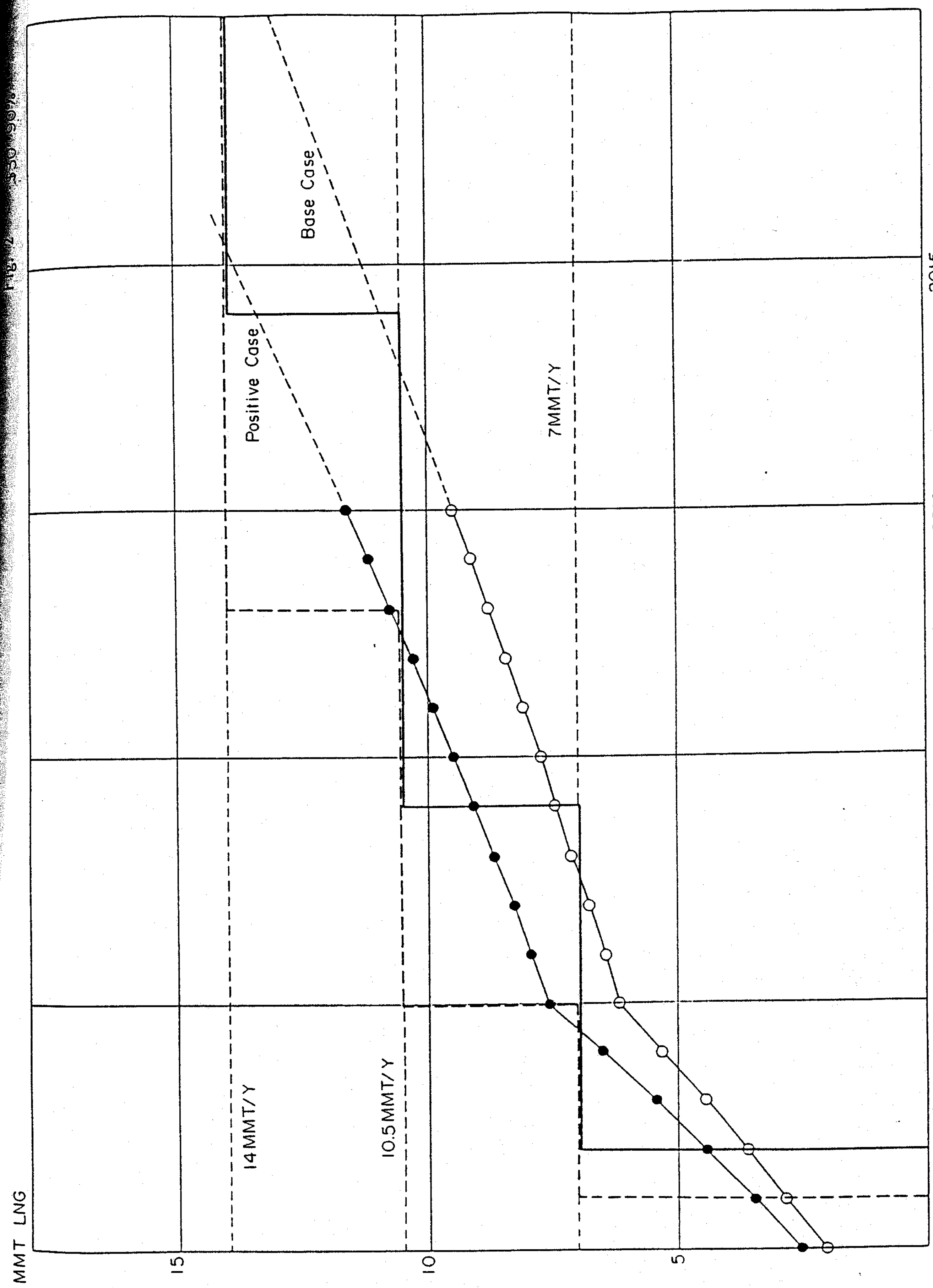
Crude Oil Price in 2000 : $25
LNG Price Parity : 80%

1995	27,653	9,596	350	37,599	510	38,109	34,000	4,109	3,698	4,520
1996	28,526	9,946	350	38,822	620	39,442	34,000	5,442	4,898	5,986
1997	29,426	10,309	350	40,085	730	40,815	34,000	6,815	6,134	7,497
1998	30,355	10,685	350	41,390	840	42,230	34,000	8,230	7,407	9,053
1999	31,314	11,074	350	42,738	950	43,688	34,000	9,688	8,719	10,657
2000	32,302	11,478	350	44,130	1,050	45,180	34,000	11,180	10,062	12,298
2001	32,539	11,782	350	44,671	1,070	45,741	34,000	11,741	10,567	12,915
2002	32,778	12,094	350	45,222	1,090	46,312	34,000	12,312	11,081	13,543
2003	33,019	12,414	350	45,783	1,110	46,893	34,000	12,893	11,604	14,182
2004	33,261	12,742	350	46,353	1,130	47,483	34,000	13,483	12,135	14,831
2005	33,506	13,080	350	46,936	1,150	48,086	34,000	14,086	12,677	15,495
2006	33,751	13,426	350	47,527	1,170	48,697	34,000	14,697	13,227	16,167
2007	33,999	13,781	350	48,130	1,200	49,330	34,000	15,330	13,797	16,863
2008	34,248	14,146	350	48,744	1,220	49,964	34,000	15,964	14,368	17,560
2009	34,500	14,521	350	49,371	1,240	50,611	34,000	16,611	14,950	18,272
2010	34,753	14,905	350	50,008	1,270	51,278	34,000	17,278	15,550	19,006

* : Include LNG demand for Fuel Cells (1995 ; 473, 2000 ; 924, 2010 ; 1,932)

Fig. 1 $30, 100 %


MMT LNG
15
10
5
14 MMT/Y
10.5 MMT/Y
7 MMT/Y
Positive Case
Base Case
1995
2000
2005
2010
2015
Note: 1. Requred Construction Costs are as follows;
1st phase (7mmt/y): 7333mm$
2nd phase (10.5mmt/y): 1026mm$
3rd phase (14mmt/y): 668mm$
Note: 2. Supply must be gradually increased.


MMT LNG
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Positive Case
Base Case
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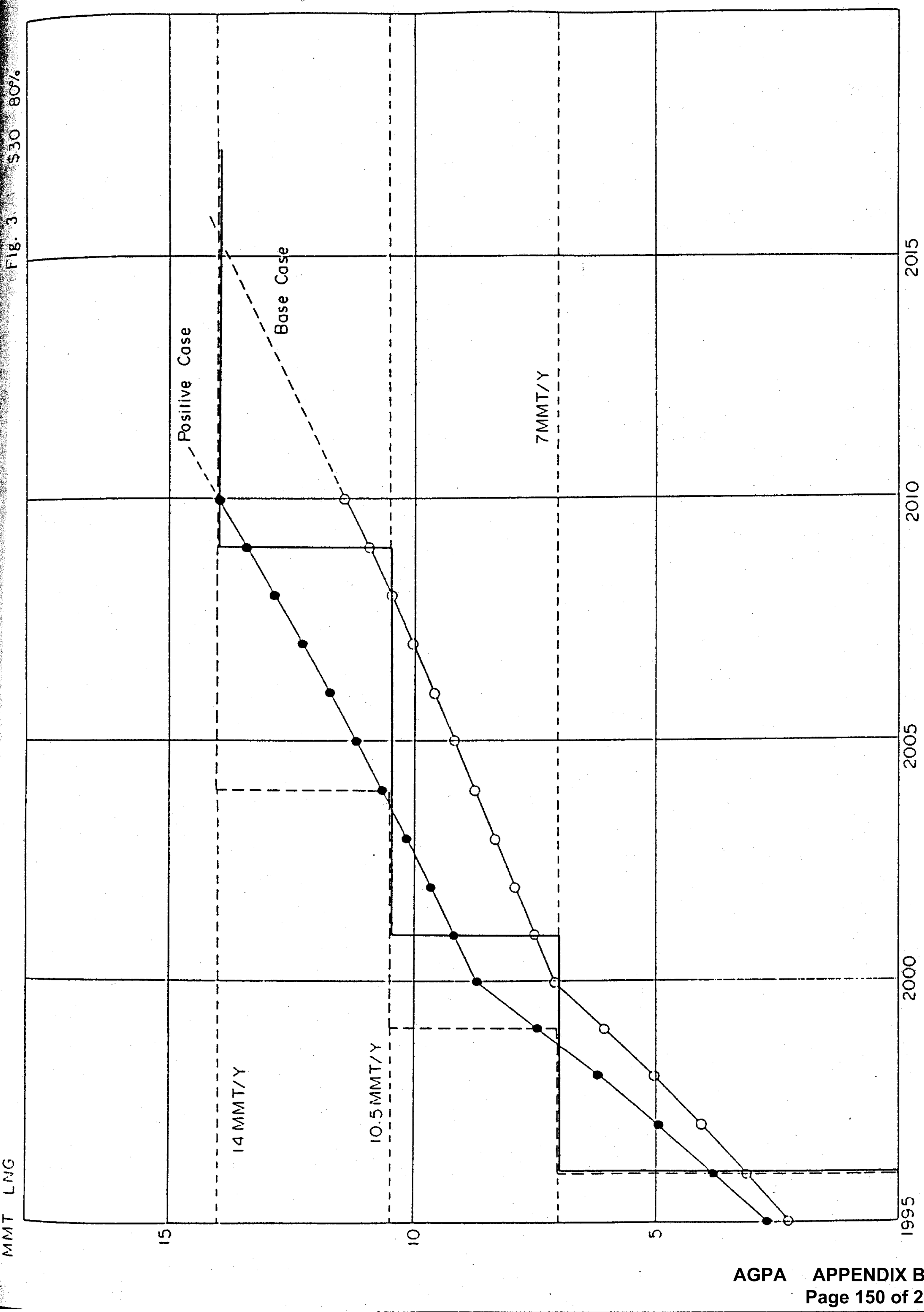
Fig. 3 $30 80%
MMT LNG
15
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1995
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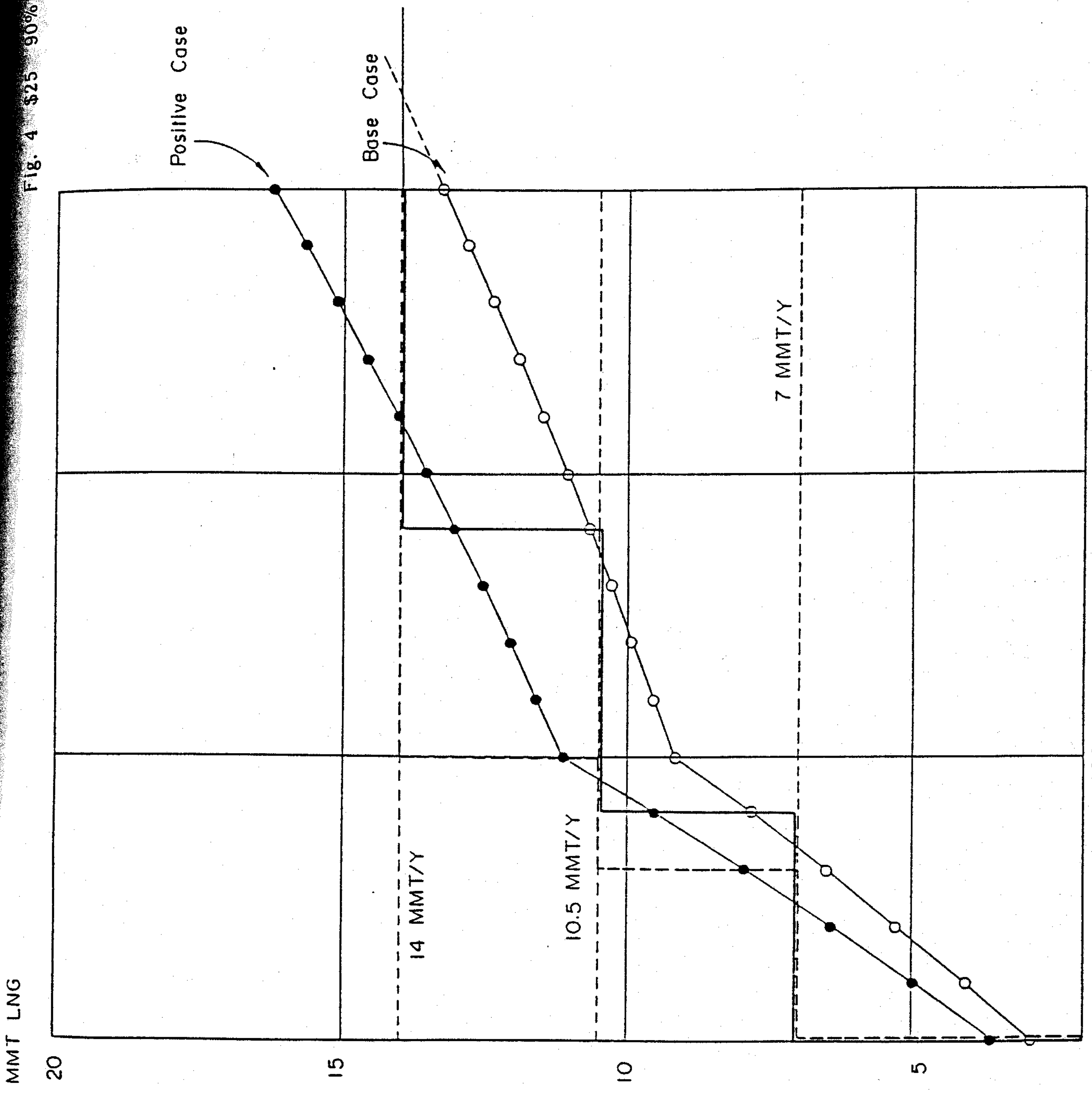
2015
14 MMT/Y
10.5 MMT/Y
7 MMT/Y
Positive Case
Base Case


MMT LNG
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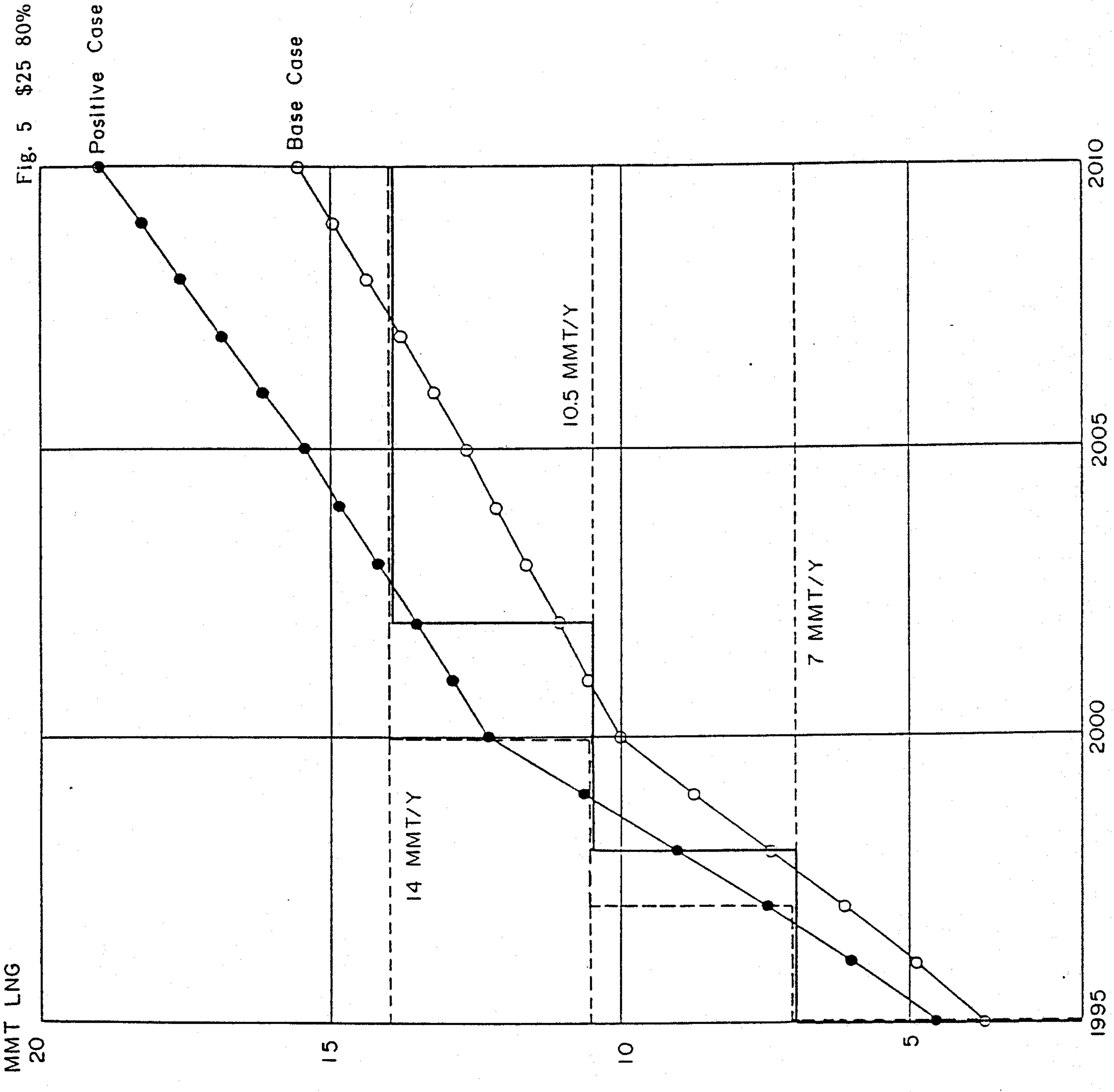
2000
2005
2010
14 MMT/Y
10.5 MMT/Y
7 MMT/Y
Positive Case
Base Case
Fig. 4 $25 90%


MMT LNG
20
15
10
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1995
2000
2005
2010
Positive Case
Base Case
14 MMT/Y
10.5 MMT/Y
7 MMT/Y
Fig. 5 $25 80%

F

EVAULATION OF THE FEASIBILITY OF EXPORTING NORTH SLOPE ALASKA GAS AS LNG

Prepared

by

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Prepared for

YUKON PACIFIC CORPORATION

June 1987

EXECUTIVE SUMMARY

The Institute of Gas Technology has performed a pre-feasibility study combining the study made by Japan's Institute of Energy Economics (IEE) of a project to export up to 14 million tons/yr of North Slope Alaskan gas as LNG to Japan, along with studies of other Asian markets. The purpose of the study is to answer the question: Is the project economically feasible by combining other markets with the Japanese markets?

The results of this evaluation are:

- North Slope gas as LNG can compete in the Japanese and Korean markets with alternative LNG suppliers.
- Buildup of LNG deliveries to these countries will likely be limited by commercial rather than technical factors.
- If the Alaska project follows a buildup schedule similar to the Australia to Japan Project:
  - Japanese demand alone will exceed the available production from a 7 million tons/yr project implemented on the standard schedule under all of the IEE demand scenarios.
  - There are many scenarios under which initial project deliveries can be justified well before scheduled start-up of deliveries in 1998.
- Addition of the Korean market significantly increases the ability to market the full 14 million tons/yr of Alaskan LNG.
- Construction of project facilities should proceed in phases with the first phase scheduled for 7 million tons/yr and construction of subsequent facilities implemented as increased markets justify them.
- Estimated costs associated with construction and operation of a 7 million tons/yr project require a C.I.F. LNG price equivalent to $24/bbl crude oil.
- LNG prices in excess of the equivalent of $24/bbl crude oil are likely to be reached in the earliest years of LNG shipments from the project.

Our evaluation of the data developed to date supports the conclusion that by combining the Pacific Rim markets and using a reasonable rate of buildup for the project of 7 million and 14 million tons/yr, the project is economically feasible.

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Introduction

The purpose of this study is to assess the feasibility of a proposed project to export up to 14 million tons per year of North Slope Alaska gas as LNG to Japan and to answer the question of whether it is realistic to continue to evaluate the feasibility of the project based on the data developed to date.

In this evaluation, we have examined and identified potential markets for the Alaskan LNG. For each of the potential markets, we have estimated its size over the period of time during which a North Slope Alaska project might be developed. Using a reasonable rate of buildup for a project with capacities of both 7 million and 14 million tons/yr (one-half and full-capacity), we have compared the growth of market demand with the project buildup to determine when deliveries of Alaskan LNG could be initiated and when the full 14 million tons/yr might be placed into the market.

The evaluation also includes an economic analysis of the project. The analysis assumes that the project will be developed in two phases. The first phase will be implemented at a level of 7 million tons per year but includes pipeline facilities design to accommodate a 14-million-ton/yr project. Implementation of the second phase, when markets are adequate to absorb the additional volumes of LNG, would include installation of additionally required pretreatment, pipeline, liquefaction, and marine transport facilities.

Numerous sources of information were used in preparing this pre-feasibility study. One of these was the project pre-feasibility study developed by Japan's Institute of Energy Economics (IEE) for this project.*

The Markets for North Slope LNG

The logical markets for North Slope LNG are the Pacific Rim countries. Of those countries, the Soviet Union, United States, Canada and Japan are major consumers of natural gas, Table 1.

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*Institute of Energy Economics, AAGS (Alaska Asian Gas System) Feasibility Study. Tokyo, May 1987.

Table 1. Natural Gas Consumption in 1985

Country	Volume, 10^9 m^3
USSR	536.2
USA	499.4
Canada	56.6
UK	53.8
Germany	46.5
Japan	40.4
Other Asia	39.5
Netherlands	37.1

The Soviet Union is not a potential importer of natural gas. Its own indigenous reserves are adequate to supply its needs far into the next century with sufficient surplus to provide for substantial exports to other countries of the Pacific Rim.

To a lesser degree, Canada is in the same position. The bulk of Canada's proven reserves are located in its western provinces. These reserves far exceed the area's gas requirements. Consequently, most of the gas production is transported by pipeline to serve Canadian consuming centers in the East. Canada also exports significant quantities of natural gas to the United States. The West Coast of the United States is included in the markets served by Canadian exports.

For the foreseeable future, the United States is also unlikely to be a market for North Slope gas. Indigenous production combined with imports from more proximate sources in Canada and Mexico can be expected to meet projected demands for natural gas.

Of the major gas consuming countries, Japan is the largest potential Pacific Rim customer for North Slope LNG. In 1985, Japan was the sixth largest consumer of natural gas, Table 1. Its consumption was greater than that of all other Asian countries combined. Further, the portion of this consumption that was represented by imported gas, 94 percent, was significantly larger than for any other major gas consuming country. Hence, Japan already has a significant role as a major gas importer and specifically as an importer of LNG.

Korea is a second Pacific Rim country with significant potential for importation of natural gas. As with Japan, it has a very limited potential for indigenous production. Similarly, Korea's population is concentrated in major centers for which environmental concerns promote the use of non-polluting fuels such as natural gas. Korea initiated its imports of natural gas in the form of LNG in October 1986.

The Republic of China (Taiwan) is the third Pacific Rim country with the potential for natural gas imports as LNG. Taiwan does have a natural gas industry based on indigenous natural gas reserves. Those reserves have been declining in recent years. Although gas reserves have been augmented recently by a major discovery in the Formosa Strait, the government has decided to import gas as LNG. A project to import Indonesian LNG is being implemented, with deliveries to start in 1990.

Therefore, Japan, Korea, and Taiwan are the most likely Pacific Rim markets for North Slope LNG.

In addition to considerations of supply/demand and price, the distance that the LNG will be transported must be taken into account in determining prospective markets.

The cost of LNG transportation is a significant portion of the total cost of the delivered LNG for most projects. Since the prices paid for imported LNG by Japanese buyers are based on the prices of crude oils, the variation in price between suppliers tends to be somewhat restricted. (The average delivered or C.I.F. price for LNG in March 1986 was $3.12/million Btu on a volume weighted basis. The maximum price of $3.23/million Btu, 3.5 percent higher, was paid for Indonesian LNG and the minimum of $2.81/million Btu, 9.9 percent lower, was paid for Alaskan LNG.) Assuming that the operating and maintenance costs of liquefaction are similar between plants, the funds remaining to pay for feed gas supplies to the liquefaction plant would, therefore, be affected by the distance of transport. A final consideration is that since the Japanese market is the largest LNG market, Japanese buyers have not allowed other Asian importers to receive more favorable f.o.b. pricing provisions (the price of LNG as loaded aboard the tanker) than their own contracts provide. Therefore, it is largely only the differences in transportation costs that will be reflected in delivered prices to other Asian markets.

The one-way marine transportation distance for North Slope LNG is approximately 3350 nautical miles to Japanese terminals. This compares quite favorably to the average transportation distance of approximately 2950 nautical miles for Indonesian exports to Japan. Exports from Brunei and Malaysia have a slight advantage at an average transportation distance of 2450 nautical miles.

For the Korean market, the North Slope marine transportation distance of approximately 4000 nautical miles places it at a disadvantage compared to Indonesia with an average transportation distance of approximately 2750 nautical miles and a Malaysia and Bruneia distance of 2150 nautical miles.

For the Taiwanese market, the transportation distance disadvantage increases significantly. The distance for North Slope LNG is approximately 4550 nautical miles whereas it is 1750 nautical miles for Indonesia and only 1170 nautical miles for Malaysia and Brunei.

The conclusion is that on the basis of distance from markets, North Slope LNG could compete in the Japanese and Korean markets but would be at a significant disadvantage in the Taiwanese market. Taiwan would more reasonably be expected to provide a spot market for North Slope LNG and is, therefore, not included in the supply/demand considerations that follow.

Time Frame for Initiation of Deliveries

It is necessary to define the time frame for which the market must exist to support the desired production volumes.

The schedule for developing the Alaska Asian Gas System (AAGS) is presently as follows:

- Phase I — Preliminary Feasibility Study
  Completed June 1, 1987

- Bridge I — Coordination for Entry into Phase II

1) Japanese utility company buyers will establish a consensus as to whether there will be sufficient demand for additional LNG to warrant purchase of Alaskan LNG.

2) U.S. companies involved in the project will establish a consensus as to whether or not necessary regulatory approvals can be obtained to export the gas and whether projected LNG prices will support the project.

3) Japanese and American companies involved will decide how to establish the necessary organizations to facilitate the project.

4) A joint assessment will be made of the costs involved to implement Phase II

Duration of Bridge I — 2 years

- Phase II — Basic Design and Engineering

Duration of Phase II — 3 Years

- Bridge II — Coordination for Entry into Phase III

1) Completion and signing of LNG sales and purchase agreements.
2) Establishment of companies responsible for project implementation.
3) Determination of total investment requirements and financing mechanisms.

Duration of Bridge II — 1 year

- Phase III — Detailed Design and Construction

Duration of Phase III — 5 years

According to this time table for project development, the first LNG would be delivered to buyers at the beginning of the second half of 1998. An unspecified buildup period would follow until the plateau volume of sales would be reached.

The plateau volume that has been considered for the project is 14 million tons per year.

Consideration must be given to both technical and commercial factors in estimating buildup periods.

Technical considerations typically provide the minimum buildup period and commercial considerations the maximum period. Assuming on-time completions, the LNG tankers should be capable of meeting delivery schedules after having been commissioned and placed in service. A conventional receiving terminal should be at full capacity within one to two months after receiving its cooldown cargo. The LNG export plant represents the most complex part of the LNG chain and thus forms the critical path for project buildup. Although each individual LNG plant has unique features, each of the trains at one of today's plants should be at sustainable design production within 2 to 4 months of start-up. Therefore, plant start-up dictates the technical aspect of the buildup. For a four-train plant with each train starting sequentially and allowing 3 months between trains, the buildup period would be expected to be about 1 year. For the Alaskan project, that would, at a minimum, cover the period from July 1998 to July 1999. If construction were to be staged so that two trains were constructed initially to be followed after start-up by construction of the next two trains when market volumes warranted, the first two trains would be at full production by about the end of 1998. Start-up of the last two trains would depend upon the interval between start of construction of the first and third trains.

The next LNG project to come on line will be the Australia North West Shelf Joint Venture project. It is a three-train project. Start-up of the first train is scheduled for July 1989, with the initial cargo to be delivered in October. The second train will start-up in January 1990 and presumably will be ready for full deliveries in April. The third train is scheduled for start-up in September 1993 and presumably will be ready for full deliveries by the end of 1993 — an interval of 3.75 years. It should be noted that procurement and construction of train 3 will not begin until after train 2 has started up. (Procurement and construction of train 3 are scheduled to take 3.75 years.)

The Australia-Japan project is particularly applicable to an evaluation of the buildup period for the North Slope Alaska project.

The first reason is that the project's buildup will begin in 1990, presumably in a period of a significantly reduced rate of growth in Japanese energy demand. That is also likely to be the case for the North Slope Alaska project.

The second reason is that the Australian liquefaction plant incorporates a novel process configuration specifically adopted by the project to reduce capital costs and minimize front end investment. The concept of a base-load LNG plant incorporating gas turbines rather than steam turbine drivers and air cooling rather than sea water cooling for this project was developed by Shell Internationale Petroleum Maatschappij B.V. It is particularly applicable to the liquefaction plant for the North Slope Alaska project. The concept eliminates the necessity to install the full power and cooling capacities initially, but allows these expensive components to be integrated separately into the construction of each liquefaction train. This significantly reduces front-end investment, makes financing easier to obtain and has a very positive effect on cash flows in the early years of LNG sales. Employing this Shell concept also makes it practical to match the construction and completion of each liquefaction train with the commercially dictated buildup curve.

There is no longer any reason that all of the trains of a multi-train, base-load LNG plant must be built simultaneously. To do so would result in unnecessary burdens on the amount of financing that must be obtained and the profitability of the project.

The commercially dictated buildup curve for the Australian project will not follow the path dictated by technical considerations. As presently defined by commercial considerations, the buildup in deliveries will be approximately a linear progression beginning with the first delivery in October 1989 and ending with a full plateau annual volume of 5.84 million tons in the seventh project year (April 1, 1995 to March 31, 1996). The result is that there will likely exist several periods, one as long as perhaps of 15 months, during which production potential exceeds market-demand production. The production levels actually realized during the buildup period will depend on the schedule for introducing the seven LNG tankers into the project, availability of the required receiving terminal capacities and on the realized LNG requirements of the individual Japanese utility company buyers.

If the buildup profile of the four-train North Slope Alaska project were to follow that for the Australian North West Shelf Joint Venture project, full plateau volume deliveries could also begin in the seventh project year. That conclusion is based on the fact that first deliveries would begin in the second half rather than the fourth quarter of the first project year and it might be possible to shorten the time to reach design production from the fourth train three months early. In that case, first deliveries would take place at the beginning of the third quarter of 1998 and full annual plateau volumes would be delivered beginning April 1, 2004 — the start of the seventh project year. The individual trains would be brought on-stream sequentially to meet the buildup curve.

<u>Supply and Demand for North Slope LNG</u>

In considering the timing for the availability of North Slope Alaska gas and the quantities that will be available, we have elected to use the schedule for initial delivery of LNG as July 1998. The schedule could be shifted forward or backward in time depending on the studies and coordinations required for decision making. This is the timing prescribed in the pre-feasibility study of the North Slope Alaska project just completed by Japan's Institute for Energy Economics (IEE).*

The IEE pre-feasibility study does not specify a specific buildup period for the project. For the reasons cited previously, we have elected to use a buildup period based on the Australian project. That basis would mean that one-half of the project's total capacity (7 million tons per year) would be available for the market on May 15, 2001 and the full capacity at the start of the seventh project year on April 1, 2004.

The IEE pre-feasibility study considered that all of the LNG must be dedicated to the Japanese market. That might indeed be the case if Japanese institutions were to be the source of all of the project financing with the Japanese utility company buyers providing the appropriate guarantees for that financing. There is no indication at this point in the development of the project that this will be the actual case. Therefore, we have included the possibility of marketing North Slope Alaska LNG in the Korean market.

For this evaluation, we are considering the Japanese market to be the larger and the preferred market for the LNG. Therefore, in this evaluation of the pre-feasibility of a project to export North Slope Alaskan gas, we will initially evaluate the possibility of supporting a project directed solely to the Japanese market and then add the volume of potential Korean sales to evaluate its impact. Further, we will evaluate the potential market in terms of demand for 7 million tons developing over a 34.5 month period followed by a second increment of 7 million tons over another 34.5 month increment. This will be done since it is technically possible to construct the project at one-half capacity, delaying the implementation of the second half of the capacity until the market warrants. In this vein, the economic feasibility of constructing the project at one-half capacity with provisions to expand it at a later date to full capacity will also be evaluated.

The basis used to determine the capability of the Japanese market to absorb the volumes of North Slope Alaska LNG over the time allotted for buildup is that of the IEE pre-feasibility study.

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*Institute of Energy Economics, AAGS (Alaska Asian Gas System) Feasibility Study. Tokyo, May 1987

Japanese Market

The IEE's forecast of LNG demand between 1985 and 2010 was made using its econometric model. The model consists of a macro economic model, an industry realization model and an energy demand-supply model. A simplified model was used to predict demand between 2010 and 2030. Potential LNG demand that has been created by new technologies and new consuming areas was evaluated separately.

The principal inputs into the model included the following:

1) Real economic growth
   3.1% annually 1985-2000
   2.5% annually 2000-2010

2) The value of the yen will remain strong, supported by a continuing trade surplus. Exports will level off due to trade frictions and yen appreciation. Domestic demand will support lowered economic growth but not a continued high growth level.

3) Production levels of basic industries will decline to a level supported by domestic demand.

4) LNG demand is reduced significantly if price continues at crude oil parity. Therefore, LNG demand is evaluated at 90% and 80% of crude oil price.

5) Oil prices (real price, FOB) used for this study in $/bbl are as follows:

	1986	2000	2010
$25 Case	15	25	30
$30 Case	17	30	40

6) Coal prices, CIF used for this study in $/ton are as follows:

   1986 - 42
   1990 - 46
   2000 - 54

7) Nuclear power generated in the year 2000 will be:

   51 GW in $25/bbl crude oil price case
   53 GW in $30/bbl crude oil price case

Based on its evaluation process, the IEE determined the following additional demand for LNG above the 34 million tons/yr already under contract, Table 2.

Table 2. Estimated Additional LNG Demand, Million Tons/Yr.

	$ 30 Case		$ 25 Case	
	90%	80%	90%	80%
1995	2.3	2.4	3.2	4.1
2000	6.9	7.9	10.1	11.2
2005	8.6	10.2	12.3	14.1
2010	10.6	12.7	14.7	17.3

Based on its consideration of factors that could increase or decrease LNG demand in the Japanese market, two sets of projected demand were selected for evaluating the capacity of the Japanese market to absorb the North Slope Alaska LNG. They were 90 percent and 110 percent of the estimated additional demand of Table 2. These sets of projected demand were termed Base Case, Table 3, and Positive Case, Table 4.

Table 3. Base Case LNG Demand, Million Tons/Yr.

	$ 30 Case		$ 25 Case	
	90%	80%	90%	80%
1995	2.1	2.2	2.9	3.7
2000	6.2	7.1	9.1	10.1
2005	7.7	9.2	11.1	12.7
2010	9.5	11.4	13.2	15.6

Table 4. Positive Case LNG Demand, Million Tons/Yr.

	$ 30 Case		$ 25 Case	
	90%	80%	90%	80%
1995	2.5	2.6	3.5	4.5
2000	7.6	8.7	11.1	12.3
2005	9.4	11.2	13.5	15.1
2010	11.7	14.0	16.2	19.0

The data from the Base and Positive Cases are plotted against the project buildup curve in Figures 1 and 2.

For the Base Case Japanese demand, Figure 1, it would be possible to implement a North Slope Alaska project of 7 million tons/yr under all four price scenarios. The delivery capacity, however, would exceed demand by a slight amount over a period of about two years if the LNG price were 90 percent of real crude oil prices in the $30/bbl case. Full deliveries would be delayed until about mid-May 2001 in this instance. Realistically, the possible shortfall of demand is well within the uncertainties of IEE's projection.

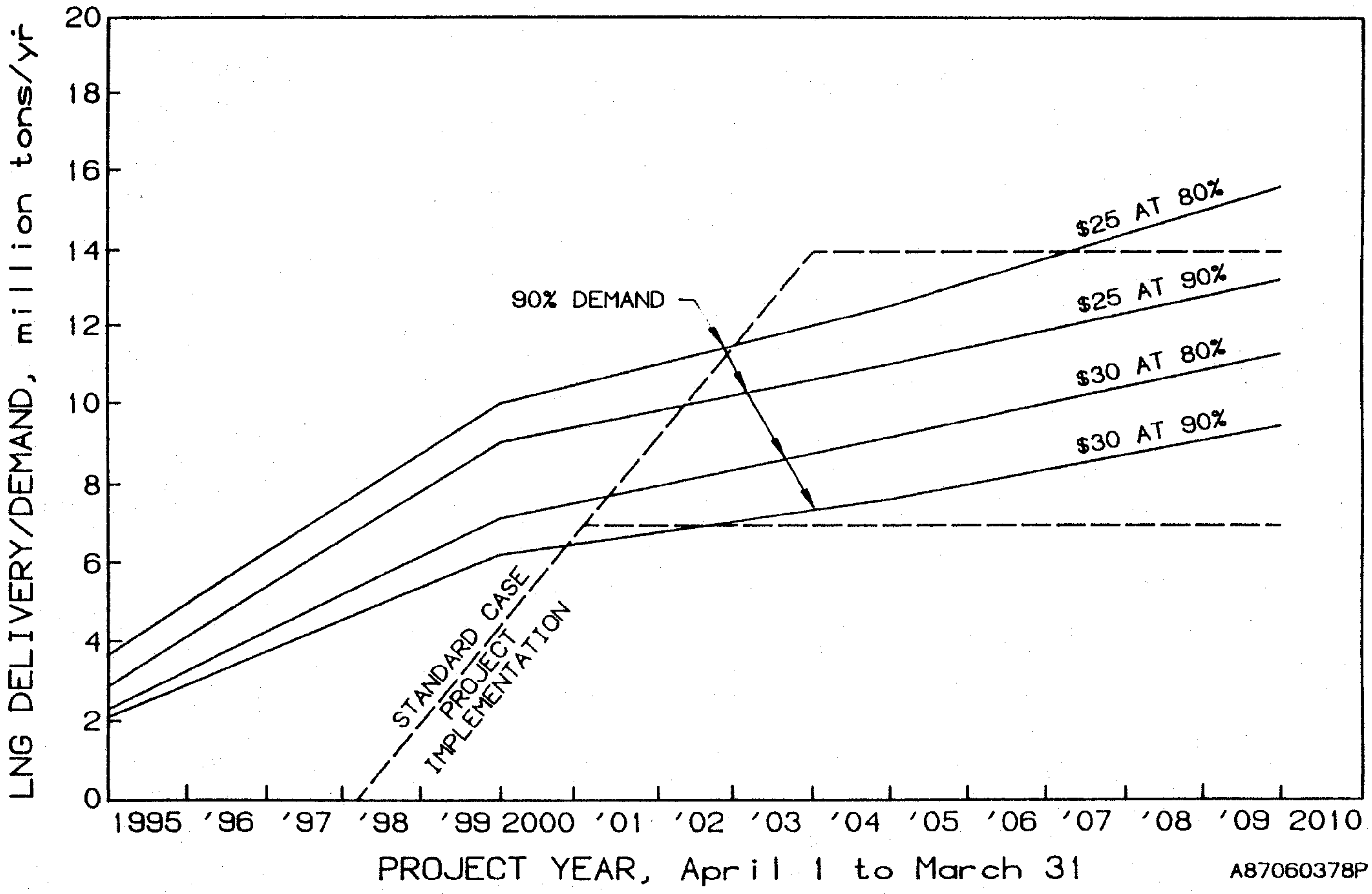

Figure 1. Project Implementation, Base Case - Japanese Demand

Based on the different demand projections, a 7-million-tons/yr project could begin production at earlier dates than July 1, 1998 as follows:

Base Case LNG Price	Initial Delivery	Full Volume
$30 at 80%	May 15, 1997	April 1, 2000
$25 at 90%	July 1, 1995	August 15, 1998
$25 at 80%	October 1, 1994	November 15, 1997

In each of the above instances, Japanese demand would exceed available supplies during the buildup period.

From Figure 1, it can be seen that it will not be possible to implement a full project of four liquefaction trains delivering 14 million tons/yr in a linear buildup under these four basic demand scenarios. It would be necessary to delay the construction of the last two trains until LNG demand warrants their construction. Such a delay is technically feasible.

For the Base Case in which the LNG is priced at 80 percent of real crude oil prices in the $25/bbl case, the interval between reaching full deliveries of 7 million tons/yr and initiating deliveries for the second 7 million tons/yr would be 6.25 years. The intervals would be substantially longer for the other price scenarios. They would be of such duration for the $30 crude oil case that uncertainty in the demand forecast limits their value in project planning.

It would also be possible to implement a North Slope Alaska project of 7 million tons/yr under all four price scenarios of the Positive Case, Figure 2. In each case, Japanese demand for LNG would significantly exceed available supply for a project with initial deliveries beginning July 1, 1998.

Based on the different demand projections, initial deliveries for a 7 million tons/yr project could begin production as early as the following dates:

Positive Case LNG Price	Initial Delivery	Full Volume
$30 at 90%	November 15, 1996	October 1, 1999
$30 at 80%	January 1, 1996	November 15, 1998
$25 at 90%	August 15, 1994	July 1, 1997
$25 at 80%	May 15, 1993	April 1, 1996

Again, in each of these instances, Japanese demand would exceed available supplies during the buildup period.

In order to begin deliveries by mid-May 1993, for example, it would be necessary to reduce the 11-year project schedule (Standard Case) by slightly over 5 years. It is certainly technically feasible to do so. Whether or not it can be done practically will depend on commercial considerations between the parties involved and on the time required to secure necessary Japanese and American regulatory approvals.

From Figure 2, it can be seen that it is possible to implement a 14-million-ton/yr North Slope Alaska project for Positive Case demand projections based on LNG prices at both 80% and 90% of real crude oil prices in the $25/bbl case without any significant delay in buildup from a date of July 1, 1998 for initial deliveries. Using these Japanese projections, the time at which to initiate deliveries of the second 7 million tons/yr at 90 percent of real crude oil prices in the $30/bbl case is so long as to make its estimation meaningless.

The earliest possible date to implement deliveries for each phase of the 14-million-ton/yr project to export North Slope Alaska LNG using the selected buildup rate would be as follows:

Positive Case LNG Price	1st 7 million Tons/Yr. Initial Delivery	1st 7 million Tons/Yr. Full Volume	Interval, Months
$30 at 80%	January 1, 1996	November 15, 1998	115
$25 at 90%	August 15, 1994	July 1, 1997	82.5
$25 at 80%	May 15, 1993	April 1, 1996	44

Positive Case LNG Price	2nd 7 million Tons/Yr. Initial Delivery	2nd 7 million Tons/Yr. Full Volume
$30 at 80%	May 15, 2007	April 1, 2010
$25 at 90%	May 15, 2003	April 1, 2006
$25 at 80%	January 1, 2000	November 15, 2002

It is concluded that on the basis of the Japanese market alone, a 7-million-ton/yr project is feasible under all of the IEE's demand projections. For the Base Case LNG price, a project of this size could be implemented as early as October 1994, and for the Positive Case as early as mid-May 1993. Implementation of the second phase of the project involving import of a total of 14 million tons/yr, however, would only be practical under the Positive Case demand at the lowest LNG prices without additional demand outside the Japanese market. For most of the other IEE demand

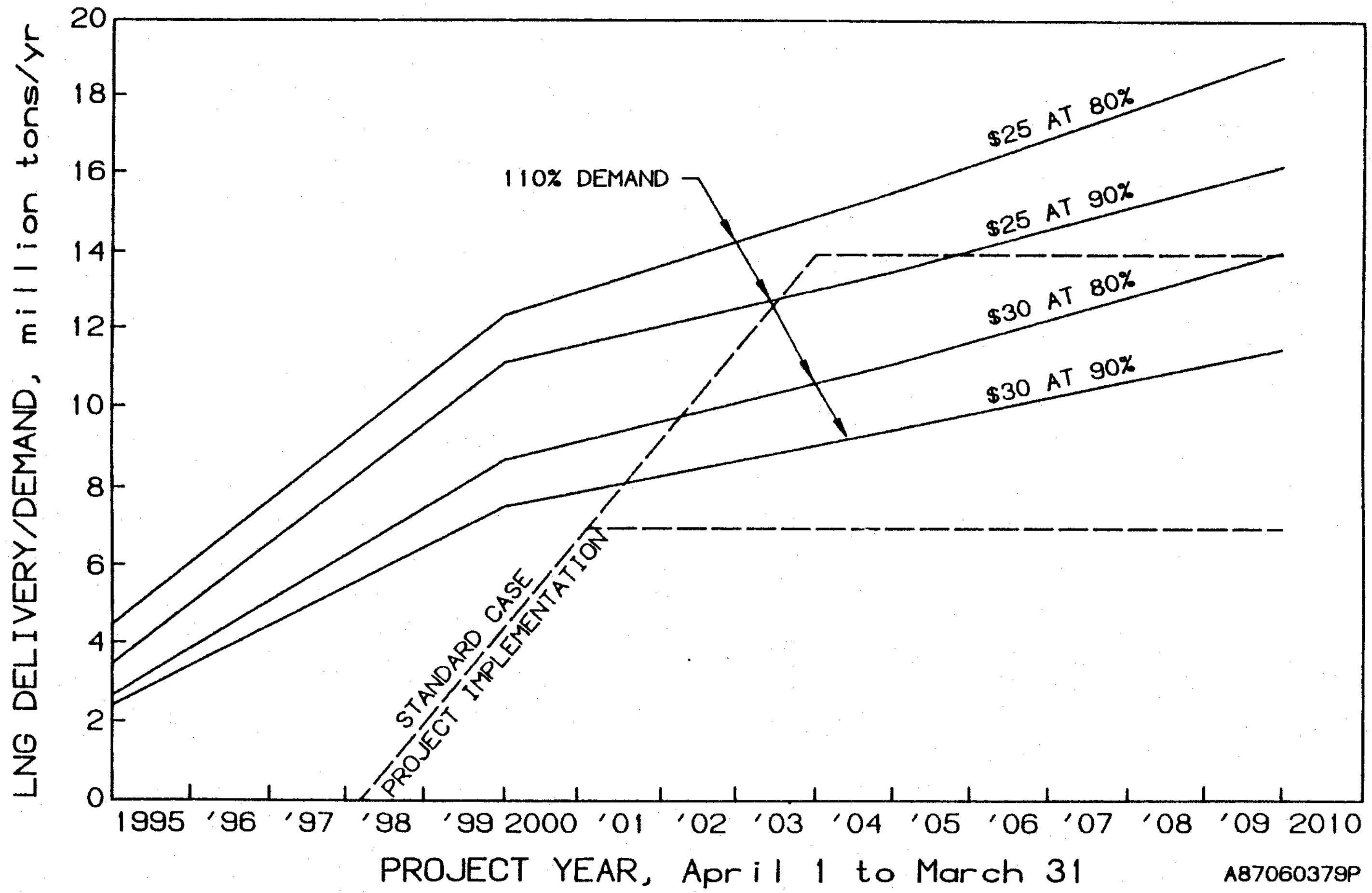

Figure 2. Project Implementation, Positive Case - Japanese Demand

projections, the time interval between implementing the first and second phases would result in the second phase being essentially a new project.

Korean Market

Korea began to import LNG for use in electric power production and town gas distribution at the end of October 1986. By the third quarter of 1987 deliveries will have reached a plateau volume of 2 million tons/yr. The source of the LNG is Indonesia.

Unfortunately, an econometric model for predicting Korean demand beyond the present import level is not publically available.

Mr. H. B. Sunwoo, Vice-President of Korea Gas Corp., presented a paper at GasTech 86 in November 1996 presenting a forecast of LNG demand and supply.* His projection was that starting in 1986 an additional 1 million tons/yr would be imported to Korea Gas' existing LNG receiving terminal at Pyeong Taek near Inchon and that in the same year an additional 2 million tons of LNG would be imported into a new terminal to be built to serve the southeast area of Korea. Total Korean imports would, therefore, be increased by 3 million tons/yr beginning in 1996. It is not clear from the paper when the buildup period would begin or how long it would take. Between 1996 and 2001, the end of Mr. Sunwoo's projection, no additional LNG imports were forecast.

Therefore, for this pre-feasibility evaluation, we will consider that additional Korean demand for LNG is 3 million tons/yr in fiscal 1996 (April 1, 1996 through March 31, 1997) and remains at that level for the period under consideration.

To the Japanese demand data from the Base and Positive Cases we have added the projected Korean demand data, plotting the results against the North Slope Alaska LNG project buildup curve (Figures 3 and 4).

For the Base Case Japanese demand, the addition of 3 million tons/yr of Korean demand means that it would be possible to begin initial deliveries for a 7 million tons/yr North Slope Alaska project as early as between April 1, 1994 and February 15, 1995 as follows:

*Sunwoo, H. B., "Korea Plans for LNG Imports," Proceedings of GASTECH 86 LNG/LPG Conference Hamburg, Germany, November 25-28, 1986, 66-67. Herts, England: Gastech Ltd., 1987.

Base Case LNG Price	Initial Delivery	Full Volume
$30 at 90%	February 15, 1995	January 1, 1998
$30 at 80%	January 1, 1995	November 15, 1997
$25 at 90%	August 15, 1994	July 1, 1997
$25 at 80%	April 1, 1994	February 15, 1997

The April 1, 1994 startup date is 18 months earlier than for the Base Case Japanese demand with the LNG price at 80% of the real crude oil prices of the $25/bbl case excluding the additional Korean demand. For the Base Case Japanese demand with LNG priced at 90% of real crude oil prices of the $3/bbl case, the date of initial delivery is reduced from mid-May 2001 to February 15, 1995 by the addition of Korean demand.

A similar positive effect is noted if the project is extended to the full 14 million tons/yr for the combined Korean and Japanese Base Case demands, Figure 3. (The principal effect of the additional Korean demand is to compensate for the reduced rates of increase in Japanese demand beyond the year 2000.) The resulting earliest possible date to implement deliveries for each phase of a 14 million tons/yr of North Slope Alaska project using the selected buildup rate are as follows:

Korean Plus Japanese Base Case LNG Price Demands	1st 7 Million Tons/Yr Initial Delivery	Full Volume	Interval, Months
$30 at 80%	January 1, 1995	November 15, 1997	112.5
$25 at 90%	August 15, 1994	July 1, 1997	52.5
$25 at 80%	April 1, 1994	February 15, 1997	0

Korean Plus Japanese Base Case LNG Price Demands	2nd 7 Million Tons/Yr Initial Delivery	Full Volume
$30 at 80%	April 1, 2006	February 15, 2009
$25 at 90%	November 15, 2001	October 1, 2004
$25 at 80%	February 15, 1997	January 1, 2000

For the most optimistic demand profile, it would be possible to initiate a North Slope Alaska project as early as April 1994, expanding to the full volume of 14 million tons/yr with no delay in implementation. That is over four years earlier than the standard project timetable.

The intervals between implementation of the first and second phases based on the higher, $30/bbl oil, LNG price are of such length as to effectively render the second phase a new project.

Adding the projected Positive Case Japanese demand scenario to the projected Korean demand improves the probabilities of being able to implement both the 7 million and 14 million tons/yr North Slope Alaska project at earlier dates, Figure 4. It also facilitates construction of the full project without the necessity of including a time interval between completion of the buildup of the first phase of 7 million tons/yr and initiation of deliveries under the second phase of an additional 7 million tons/yr.

For the Positive Case Japanese demand, the addition of 3 million tons/yr of Korean demand beginning in 1996 means that it would be possible to implement a 7 million tons/yr North Slope Alaska project between October 1, 1993 and October 1, 1994 as follows:

Base Case LNG Price	Initial Delivery	Full Volume
$30 at 90%	October 1, 1994	August 15, 1997
$30 at 80%	August 15, 1994	July 1, 1996
$25 at 90%	January 1, 1994	November 15, 1996
$25 at 80%	October 1, 1993	August 15, 1996

The earliest possible dates to implement deliveries of 14 million tons/yr of North Slope Alaska LNG based on the Positive Case Japanese demand plus the Korean demand are as follows:

Korean Plus Japanese Positive Case LNG Price Demands	1st 7 Million Tons/Yr		Interval, Months
	Initial Delivery	Full Volume	
$30 at 90%	October 1, 1994	August 15, 1997	88.5
$30 at 80%	August 15, 1994	July 1, 1996	6.6
$25 at 90%	January 1, 1994	November 15, 1996	1.5
$25 at 80%	October 1, 1993	August 15, 1996	0

Korean Plus Japanese Positive Case LNG Price Demands	2nd 7 Million Tons/Yr	
	Initial Delivery	Full Volume
$30 at 90$	January 1, 2006	November 15, 2008
$30 at 80%	January 1, 2002	November 15, 2004
$25 at 90%	January 1, 1997	February 15, 2000
$25 at 80%	August 15, 1996	July 15, 1999

For this demand profile, it would be possible to initiate a North Slope Alaska project as early as October 1, 1993, expanding to the full volume of 14 million tons/yr with no delay in implementation. That is 7 months earlier than for the sum of Korean and Base Case Japanese demands cited above and almost 5 years earlier than the standard case.

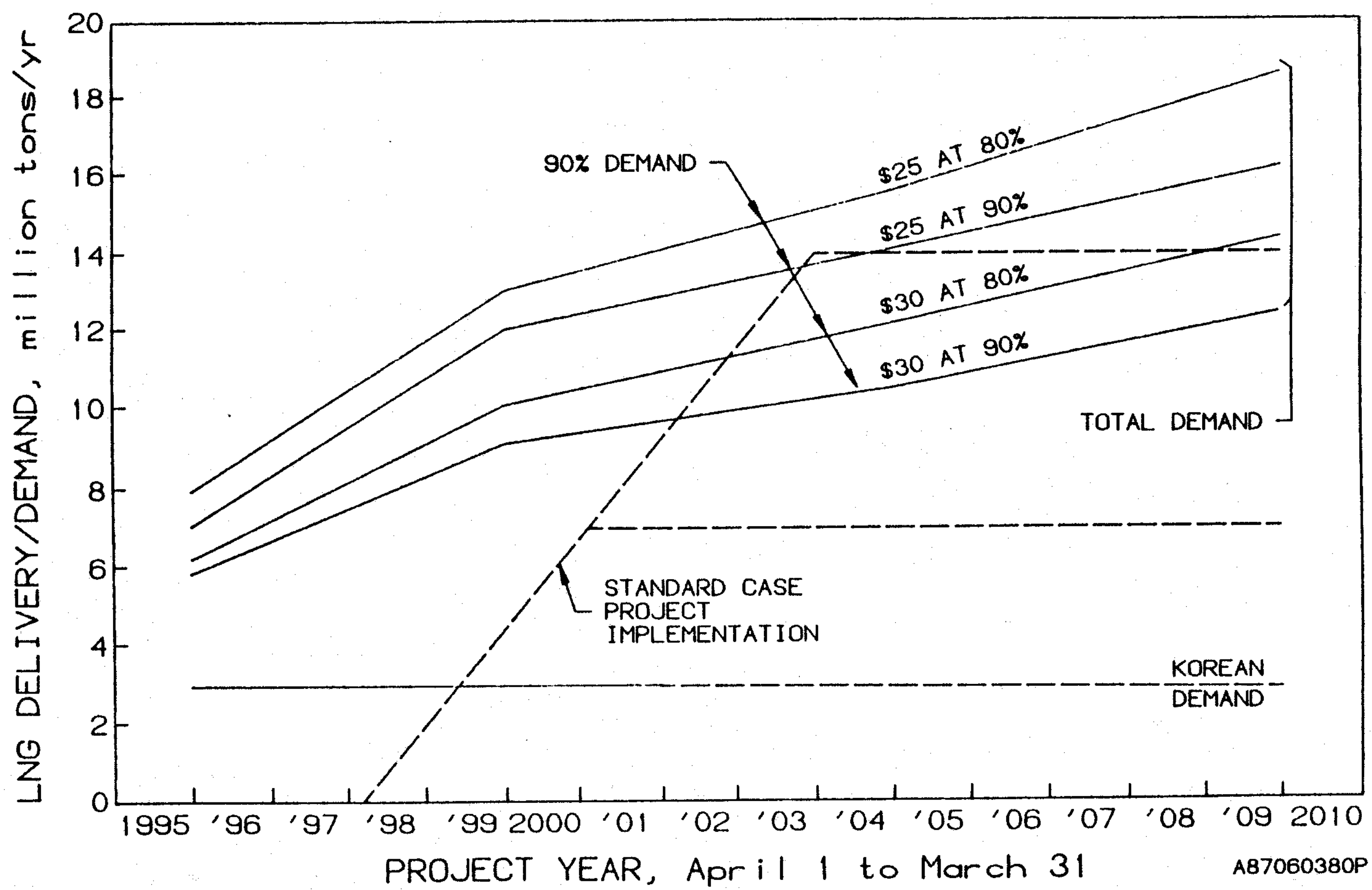

Figure 3. Project Implementation, Korean Demand Plus Base Case - Japanese Demand

The demand profile is also such that it would be possible to implement a full scale project in the other Positive Demand Case where LNG is priced at 90 percent of $25 oil. It would be conceivable to implement a full-scale project in the Positive Case with LNG priced at both 90 and 80 percent of $30 oil, since the interval between phases is not considered to be so excessive as to render the second phase a new project. By the time construction of the first phase was initiated, a much more precise picture of Pacific Rim demand and the commercial realities of the second phase of a North Slope Alaska project would be known.

It is concluded that the addition of 3 million tons/yr of Korean demand has its greatest impact on the implementation of the second phase of a North Slope Alaska project. Adding the Korean demand to that of the Japanese market makes the implementation of a full-scale project feasible for all of the scenarios with the possible exception of the lowest demand based on the highest LNG price.

Project Economics

In its pre-feasibility study, the IEE based its project economic analysis on the assumption that all investments would be made before the year 2000. As demonstrated above, the standard case in the pre-feasibility study for project implementation calls for initial deliveries beginning on July 1, 1998. With a reasonable buildup rate, as that for Australia's North West Shelf Joint Venture project, full deliveries of 14 million tons/yr would not be achieved until April 1, 2004.

This delivery buildup, or any other that extends beyond the year 2000, requires the investors to carry an enormous burden of facilities installed but not productive. This manner of scheduling of the installation of facilities virtually assures a negative response from an investor's point of view.

It seems more useful to schedule investments on the basis of a two-phase construction schedule that coordinates the technical and economic factors of construction with market development. On this basis it is reasonable to build pipeline facilities to accommodate a 14-million-ton/yr project because their cost for a half size project is nearly as large as for 14 million tons/yr. Since we cannot know the magnitude of future economic activity in Japan or the future price of oil to Japan but can only estimate their magnitudes; it is

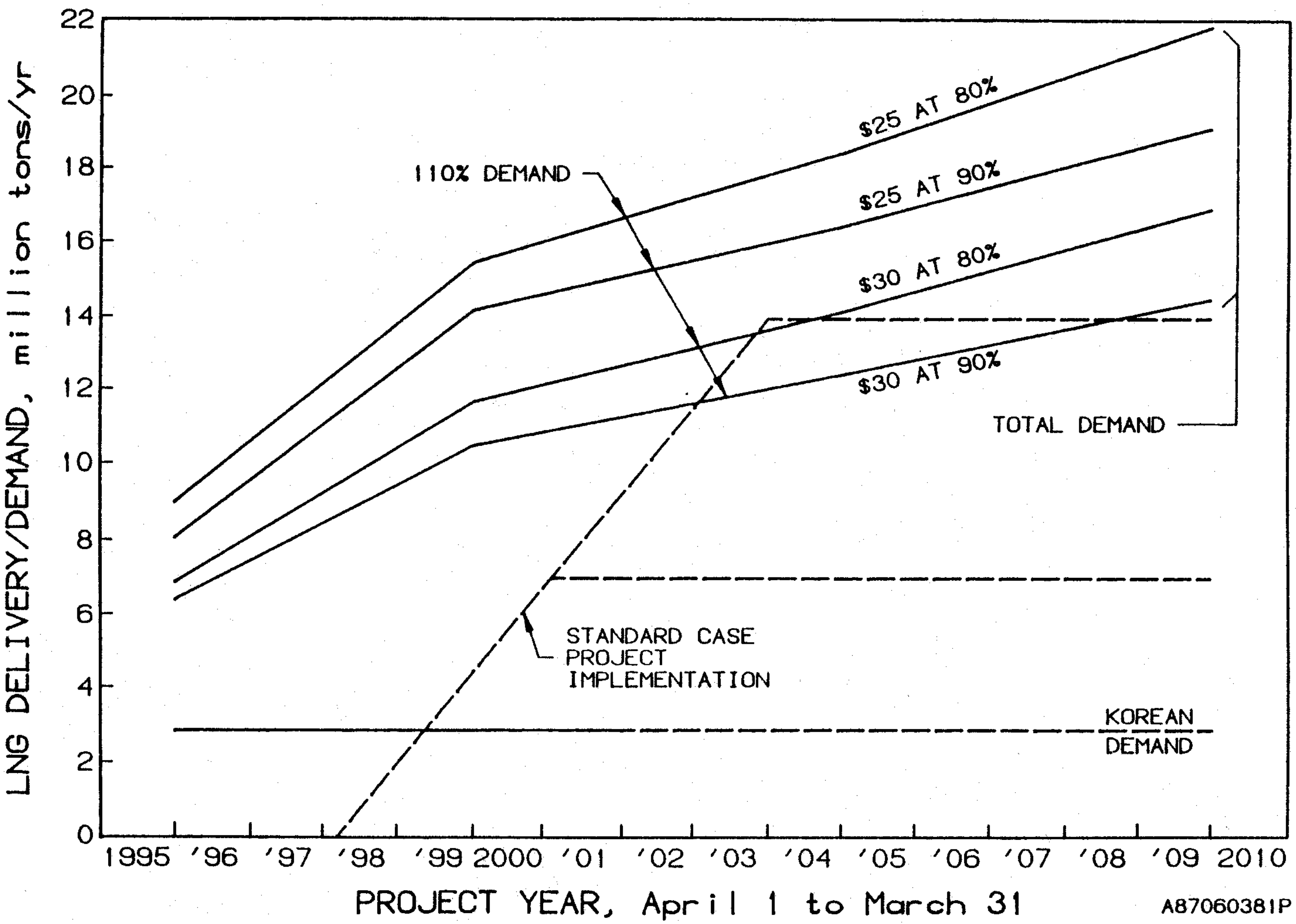

Figure 4. Project Implementation, Korean Demand Plus Positive Case - Japanese Demand

important to limit Phase-1 investments (a 7-million-ton/yr project) in gas conditioning and liquefaction facilities and in LNG ships to those required for Phase 1. In the same way, it is useful to install train sizes that are not too large. In the preliminary study, train capacity of 530 MMSCF/d was assumed. It seems more prudent to install trains with a capacity of about 300 MMSCF/d, not only because such trains are in operation today, but also because the steps up to enlarged markets are not so large. A 530 MMSCF/d train size implies market increments of about 4.2 million tons/yr, as contrasted with the 2.4 million tons/yr for a 300 MMSCF/d train.

What is at issue here is not the precise values assigned train size or markets - those would be fixed by studies and commitments yet to be made - but the concepts of project development that bring the magnitude and timing of investments and risks under control. We believe a proper project development plan would determine its investments in Phase-2 facilities only when the economic climate after the year 2000 becomes much clearer than it is today. Thus, a project justified at the level of about 7 million tons/yr should not be dis-credited by a commitment to expansions that cannot be justified at this time.

C.I.F. Price (Japan) and Feed Gas Cost

The following analysis uses most of the basic costs of the IEE's Alaska Asian Gas System pre-feasibility study with adjustments made to reflect the above discussion and certain cost elements derived from our own sources. The resulting costs then are heavily weighted by the site-specific estimates for gas conditioning, pipelines, and ship berthing facilities for which no general cost estimates can be made. The costs below do, however, include cost elements different from those of previous studies and a different concept of interpretation. In particular, gas prices at the field have been back calculated from CIF LNG prices in Japan to establish the maximum gas price allowable given a target value for the rate of return to capital.

CAPITAL COSTS

	IEE/AAGS Study (14 million Tons/Yr) Million $	IGT Study (7 million Tons/Yr) Million $	
Conditioning*	1340	670	
Pipeline	5440	5440	
Liquefaction & storage & loading	1860	1150	(3-300 MMSCF/d trains) 2-800,000 bbl tanks
LNG ships	2370	980	7 ships
Total capital required	11010	8240	
Annual capital cost	1249	935	$, million/year

* These figures include interest during construction, 8% interest rate on debt which is 75% of capital, 14% return to equity. The average return on capital is then 9.5% per year and the capital recovery factor, 9.5%, 20 years, is 0.1135 $/year per dollar invested.

OPERATING COSTS

	$/Million Btu	$, Million/year
Plant operations	0.07	23
Ship operations	0.13	42
Debt service	1.79	590
Total- ex gas cost	1.99	655

Federal tax	34%
Other taxes	4%
Effective tax rate	36.6%

(revenue - operating expenses)*tax rate = taxes
cash flow to equity is revenue less operating costs less taxes
at the design base, return to equity is also (0.25*14/9.5)*935
= 344.5 $, million/year

revenue needed = 344.5/(1-0.366) + 655 + gas cost
= 1198 + gas cost, $, million/year

The revenues available to defray gas cost at various CIF prices are shown below on the basis of oil prices in US dollars, with the Btu value of crude taken as the average of that imported into Japan during 1985-86, 5.9 million Btu/bbl.

CIF PRICE = REVENUE			MAXIMUM VIABLE GAS FIELD PRICE*	
$/Barrel	$/million Btu	$, million/yr	$, million/yr	$/million Btu**
30	5.08	1672	475	1.26 (25% C.I.F.)
27	4.58	1506	308	0.81 (18% C.I.F.)
24	4.07	1338	140	0.37 (9% C.I.F)
21.5	3.64	1198	0	0.0

*At a central point prior to treating
**Allows 15% shrinkage for fuel and losses

The above figures incorporate the following assumptions:

1. Gas conditioning costs have been taken proportional to production level. As the pattern of gas demand in the importing markets and thus, project buildup after 1998 becomes clear, additional gas conditioning equipment can be installed as required.

2. The pipeline is built as for a 14 million tons/yr project to allow for potential expansion. Because flow capacity is proportional to pipeline diameter to the 2.6 power, there is no incentive to build a smaller line in the first phase of the project, i.e., there would be little cost advantage in the first phase but very high costs for adding significant capacity after initial construction.

3. This estimate is based on train sizes of 300 MMSCF/d because there is recent data to support the cost of this size train and trains of this size are in operation today, and because it is important for expansion that train size not require very large incremental markets. A cost of $32 million has been used for 800,000-barrel tanks. The cost of liquefaction, storage and loading is taken as that for 14 million tons/yr, less the cost of 3 trains and the cost of 2 800,000-barrel tanks.

4. Although projections of LNG ship costs typically indicate a unit cost of about $160 million for a vessel of 125,000 m^3 size, shipyards around the world are desperate for business. A recent price from a Japanese yard was $120 million. Although it seems unreasonable to use the lowest current price for this study, it is equally unrealistic to use the $160 million figure. It is in this context that the value $140 million was chosen.

5. In accounting for transportation costs it is important to keep the capital and operating costs separate to avoid counting the capital costs of the ships twice: once in the overall project and again in the transportation charge. In this study we have put ship capital costs in the overall capital costs of the project and obtained actual operating costs from ship operators. This yields a transportation cost of $0.47/million Btu. Because the transporter is typically independent of buyer or seller or both, actual transportation cost is a matter of negotiation. Since recent quoted costs are in the range $0.50 to 0.60/million Btu for similar distances, the cost used here is quite reasonable.

6. Plant operating costs vary greatly around the world. It is important not to base operating costs in the USA on costs experienced in third world countries. A plant in Alaska will not have to support an expatriate work force. It will have available skilled craftsmen and materials at far lower cost than those at most other base load LNG plants. It does not have to create and support an infrastructure in a previously undeveloped environment. It will be staffed at far lower levels than those common in third world countries.

7. Shrinkage of 15 percent has been assigned as a compromise between allocating all gas shrinkage at the conditioning plant — for injection, NGL and fuel — 16.6 percent, and allocating none there. Injection gas and the fuel expended to inject it benefits the owner of the gas, not the buyer. The natural gas liquids are credits to the project, not an expense. Shrinkage after conditioning amounts to about 10 percent, so that allocation of another 5 percent is reasonable.

8. One example showing the breakdown of the cost allocations, excluding gas cost, is

Gas conditioning	6.4%
Pipeline	51.5
Liquefaction, storage and loading	10.9
Ships	9.3
Operations	5.4
Taxes	16.5
Total	100.0%

The high pipeline cost shown here is the key factor in understanding this project. For this project to be competitive, the field price of the gas must fall within a limited range that is less than that typical of projects with shorter pipelines in a less hostile environment.

9. A second breakdown of costs, excluding gas cost, is

Debt service	49.3%
Recovery of equity capital	28.8
Operations	5.4
Taxes	16.5
Total	100.0%

This example shows the importance of matching production capacity to markets. The very large proportion of fixed costs means that return to equity is very sensitive to the size of the revenue stream, i.e., to LNG price and the volume of deliveries that the market will support.

In its pre-feasibility study, the IEE projected crude oil F.O.B. prices to be between $25 and $30/bbl in real terms in the year 2000. This formed its $25 and $30 cases. The 1986 crude oil prices incorporated in the two estimations were $15 and $17/bbl respectively.

Currently, crude oil prices are stabilizing at the $18/bbl level. The June 25th Conference of OPEC Ministers in Vienna is expected to provide additional evidence as to whether this price will be maintained by increasing production of OPEC crude oil to meet increasing demands or whether the production quotas will be maintained causing crude oil prices to rise further. A third alternative available to OPEC, that of increasing both price and production, is also possible, but is given a lower probability of adoption than the first two possible choices open to the Ministers.

As a consequence of recent OPEC ability to control crude oil prices, we conclude that the $25/bbl case for crude oil prices is probably overly conservative. A price of $30 or perhaps even higher appears to be more realistic.

The IEE pre-feasibility study estimated that the cost of feed for the project would be between 0 and 20 percent of the LNG's C.I.F. price. A value of 10 percent was used in its economic evaluations. We have determined that the revenues necessary to defray a gas cost of 9 percent of the LNG's C.I.F. price is $24/bbl.

It is of interest to determine the time at which LNG prices equivalent to $24/bbl of crude would be reached according to the IEE projections. With crude oil price at $30/bbl in the year 2000, an LNG price of $24/bbl would be reached in 1994 at 100% price parity with crude and in the year 2000 at 80% parity with crude. Thus, we see that under the standard implementation schedule the IEE projections support the view that LNG prices in excess of $24/bbl will be realized in the earliest years of LNG shipments from the project and almost certainly before the year 2000. In other words, it is likely that the market price and demand will support gas field prices at least 9% of the C.I.F. price of LNG in Japan. Only in the unlikely event that crude oil prices in the year 2000 are significantly less than $30/bbl are cash flow deficiencies a likely prospect in the earliest project years.

As noted above, the field price of the gas and matching production capacity to the markets are key to the economic viability of exporting North Slope Alaska gas as LNG.

Conclusion

Of the Pacific Rim countries, Japan, Korea and Taiwan are potential importers of North Slope Alaska LNG. Of these, the Japanese market is by far the largest and may be considered as the preferred market for Alaskan LNG. Korea is also a significant potential market. Because of its transportation distance disadvantage, the Taiwanese market may more reasonably be expected to provide a spot rather than a base-load market for North Slope Alaska LNG.

According to the standard implementation time table of the pre-feasibility study, initial delivery of North Slope Alaskan LNG would be made at the beginning of the second half of 1998 — some 11 years from now. The interval to initial deliveries could be shortened or extended from a technical stand point depending on how quickly commercial agreements between the participants and necessary Japanese and American regulatory approvals are reached.

Based upon the buildup in deliveries now planned for Australia's North West Shelf Joint Venture project, full annual deliveries of North Slope Alaska LNG for the standard implementation case could be reached by April 2004, which would be the start of the seventh project year. The total buildup period to 14 million tons/yr will be 69 months, with the buildup to 7 million tons per year being 34.5 months. This delivery schedule is limited by assumptions regarding commercial rather than technical factors. Thus, more rapid buildup can be accomplished if the markets in Japan build more rapidly.

Korea's LNG demand is expected to increase by 3 million tons/yr beginning in 1996. Total LNG demand is expected to remain at an annual level of 5 million tons until 2001.

The principal impact of this additional market on implementation of a North Slope Alaska project is to facilitiate the implementation of Phase 2 of the project. It would be possible to implement a full project of 14 million tons/yr into the combined market under all but the most restrictive demand projections for the Japanese market.

Projected supply/demand for LNG in the Japanese market will vary with the real price of crude oil and on the price of LNG relative to crude oil price.

It would be possible to implement a 7-million ton/yr project solely into the Japanese market at a demand of 90 percent (Base Case) of that projected for selected LNG prices according to the standard implementation schedule. If demand increases to 110 percent (Positive Case) of that projected for selected LNG prices, it would be possible to develop a project at earlier dates. The earliest projected date for initial deliveries would be May 15, 1993 — over 5 years earlier than for the standard case.

Because the rate of increase in projected Japanese LNG demand declines after the year 2000, it would not be possible to insert the full 14 million tons per year of LNG into the Japanese market for the standard implementation schedule without a delay between implementing the first and second phases of the project except under the most favorable demand projection. For other than Positive Case demand projections, additional markets outside Japan would need to be secured before development of the second phase of a North Slope Alaska project.

Prudent scheduling of investments can be achieved by closely matching installation of production capacity to market demand and by prebuilding only those facilities, sized for full project deliveries, where a definite economic advantage can be shown. Using this philosophy, it is economic to implement a project of 7 million tons/yr initially and expand it to 14 million tons/yr at a later date.

Our evaluation of the data developed to date supports the conclusion that by combining the Pacific Rim markets and using a reasonable rate of buildup for the project of 7 million and 14 million tons/yr, the project is economically feasible.

G

Defined and/or Producing Gas Reserves
Alaska North Slope
1986
(BCF)

State Field	Gas Reserves (mid-high)	Operator	Gross Prod.	Injected	Used/Sold	Comments
Kuparuk	600-750	ARCO	92.5	68.8	23.7	All owners (8) are purchasers
Lisburne	900-1000	ARCO	25.3 (est)	20.5 (est)	4.8 (est)	
Milne Point	Not defined	Conoco	8.4 (est)	6.9 (est)	1.5 (est)	
Prudhoe Bay	29,000	ARCO & Standard	985.6	897.7	87.9	~15 BCF sold to TAPS
Endicott	800-1200	Standard	-	-	-	Production expected 1988
Point Thompson/ Flaxman Island	5,000	Exxon	-	-	-	Shut-in
Barrow	17	Private	-	-	.4	
Total Reserves	36.3 - 37.0					

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H

Representative Undefined and/or Unproducing Gas Resources
Alaska North Slope
1986

Unit/Prospect/ Field	Lease	Operator	Status (1986)	Comments
Gwyder Bay	State	Conoco	Field delineation underway; exploratory drilling	Onshore-offshore
West Sak Reservoir	State	ARCO Conoco	Pilot production underway; .005 BCF produced-1986; Reservoir delineation ongoing	Shallow sands; Kuparuk Unit
Hemi-Springs	State	ARCO	Approved production agreement	No data available
Umiat	State	-	Associated gas (shut-in 1985)	Insufficient data to assign gas reserves
E. Umiat	State	-	Shut-in	Lack of operator commitment to produce gas
Kavik	State	ARCO	Shut-in	Lack of operator commitment to produce gas
Kemik	State	Forest Oil	Shut-in	Lack of operator commitment to produce gas
UGNU	State	ARCO	Exploratory drilling	Shallow sands; presently undevelopable
Colville Delta	State	Texaco	Exploratory drilling	Insufficient data to assign reserves
North Star	State	Amerada Hess	Exploratory drilling	Offshore gravel island
Niakuk	State	Standard	Exploratory drilling	
Kaktovik	Pvt/ASRC	Chevron	Exploratory drilling	ANWR Coastal Plain
Harvard	Federal	Shell WE&P	Producible (under OCS Order 4)	Sandpiper #1 Well
Seal	Federal	Shell	Producible; temporarily abandoned	Seal Island #1
Tern	Federal	Shell	Producible; temporarily abandoned	Tern Island #1
Beechy Point	Federal	Exxon	Producible; temporarily abandoned	Salmon Island #2

I

A Study of

NATURAL GAS RESOURCES

In Support of the

TRANS-ALASKA GAS SYSTEM

APPLICATION TO THE ECONOMIC REGULATORY ADMINISTRATION

U.S. DEPARTMENT OF ENERGY

YUKON PACIFIC CORPORATION

ANCHORAGE, ALASKA

NOVEMBER, 1987

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Feasibility of the TAGS project is affected by local, national and international resources of natural gas. To evaluate various gas resource base estimates, it is important to define the boundaries, which are generally set by economics, technical feasibility, and geology. Of the total resource base, some gas is considered economically and technologically unrecoverable. The recoverable portion is considered available for production using current or foreseeable technology, under favorable economic conditions. Of the recoverable resources, some have already been discovered and produced; some remain as proved "reserves" for future production. Reserves are defined as measurable volumes of gas that are commercially recoverable from known fields by established operating practices, under existing economic conditions. Many recoverable resources have not been proved as reserves, according to the conventional definition, but are considered to have varying degrees of "potential" for recovery under predictable economic and operating conditions.

Long-term resource assessments should consider both proved reserves and potential resources, since categorization of gas is subject to revision as economic conditions change, additional geologic and engineering data become available, exploration and extraction technologies develop, and new discoveries are made.

For this reporting, approximately one hundred gas resource assessments were reviewed. Information reported in support of TAGS focuses on Alaska natural gas resources; U.S. natural gas resources, the associated gas industry, and import potential; export of U.S. gas; and market conditions in Japan, a key target for U.S. exports.

Alaska Natural Gas Resources: Alaska is a recognized storehouse of petroleum wealth, containing 20 percent of both the estimated gas reserves and potential gas resources of the Lower-48 states. Approximately 90 percent of Alaska's gas reserves are located in the North Slope oil and gas province. State of Alaska estimates include approximately 37 TCF of gas in and near the Prudhoe Bay area currently classified as recoverable reserves. Current estimates of potential gas on the North Slope range from a mean of 97 TCF to a high of 304 TCF.

Two areas of special study may contribute significantly to Alaskan reserves in the future. Recently, BLM estimated 31.3 TCF of gas in-place in the Arctic National Wildlife Refuge (ANWR); up to 23 TCF may be recoverable, according to state experts. The National Petroleum Reserve (NPR) in western arctic Alaska may contain up to 8.5 TCF of recoverable gas resources. Recoverable gas may also be available from a number of existing exploratory wells that have not yet reported adequate data for resource definition. In addition, new areas are continually being leased for exploration by state and federal agencies.

Alaska is highly dependent on the petroleum industry. With Prudhoe Bay oil production expected to drop continuously after 1988, new resources will be required to support the state's economy. Presently, almost 80 percent of the natural gas produced in association with oil production in Alaska is reinjected, due to small local requirements and limited opportunity for other commercial use. (Out of 1.4 TCF of gas produced in 1986, approximately 1.1 TCF were reinjected, 0.1 TCF used in field operations, and 0.2 TCF sold.) Development of the potential market for Alaska gas could help offset the economic downturn that will follow declining oil production and associated royalty income. Since Alaska gas is generally not considered in domestic supply forecasts, development of a market outside the U.S. would have little impact on local or national gas cost or availability.

<u>U.S. Natural Gas Resources</u>: In general, the outlook on U.S. natural gas resources is optimistic, with a steadily increasing supply through 2010 predicted by the American Gas Association. In addition, improvements in drilling and production technologies could open up new resources not yet considered in supply forecasts. Recent developments are stabilizing the industry environment to assure a long-term, economical gas supply to meet domestic needs.

The U.S. has substantial gas resources; its proved reserves of 190 TCF rank third in the world. In 1986, estimates included an additional 739 TCF of potentially recoverable gas resources in the U.S. Other estimates of conventional potential resources have ranged to 1,200 TCF; estimates including unconventional gas resources go even higher. The resource base, however, is just one factor controlling the gas market and U.S. gas industry. Other factors include regulations, industry attitudes, fuel switching capabilities, exisiting practice and infrastructure, international economics, import potential, and protectionism. A number of these factors have led to the surplus production capability, or "gas bubble", that exists in the U.S. today.

Since the early 1980's, lowered demand, lowered prices, and excess producibility have discouraged domestic exploration and development in support of future gas supplies. In 1985, U.S. demand was 17.3 TCF; 16.4 TCF were produced and 0.9 TCF imported; surplus U.S. production capability estimates ranged from 2.0 to 4.6 TCF. It is projected that U.S. production will decline going into the 1990's, and additional supplementary supplies may be required to meet estimated demands. Options to provide this supplementary gas include increasing conventional supplies, developing unconventional supplies, and expanding imports.

Conventional supplies can be increased by improving investor security, committing uncommitted nonproducing reserves, utilizing infill drilling techniques, and developing frontier projects such as the Alaska Natural Gas Transportation System. Developing unconventional supplies of gas from tight formations, deep gas, and methane from hydrates could add substantially to the U.S. gas resource base, providing up to one-third of the total U.S. supply by 2010.

Canada, with 100 TCF of proved reserves and estimates of ultimately recoverable resources to 420 TCF, is the United States' most feasible source of imported gas. Development of unconventional resources could also increase the Canadian resource base considerably. Canadian annual demand is approximately 2.0 TCF; exports total less than 50 percent of those authorized; and a gas bubble of 1.5 - 2.0 TCF exists. Canada can comfortably meet the new national surplus requirements while increasing production to boost exports if the demand exists. The 1985 production capability of Canadian natural gas was approximately 4.5 TCF, though only about 2.9 TCF were actually produced.

Other import potential comes from Mexico. Currently, Mexican reserves are estimated at 77 TCF; production was reported at 1.0 - 1.3 TCF in 1985. It is estimated that up to 4 TCF of associated gas could be produced; development of substantial resources of non-associated gas could further increase Mexican gas production capability. Supplemental imported gas could also be provided by LNG from almost any LNG resource base in the world. Algerian LNG has been imported since 1970, and the U.S. has considered importing LNG from other countries including Indonesia, Trinidad, Iran, and the U.S.S.R.

<u>Exporting U.S. Natural Gas</u>: The U.S. has exported gas via pipeline to adjoining countries for more than 40 years. For almost 20 years, Alaskan natural gas has been shipped as LNG to markets in Japan. The small amount of LNG exported from Alaska (approximately .06 TCF) essentially comprises the U.S. gas export industry today. Accelerating international trade in natural gas warrants expansion of the current U.S. role as exporter.

Increasing U.S. export potential is based on availability and accessibility of domestic resources and existence of a feasible export market. The U.S. has substantial gas resources; an amount approximately equal to 20 percent of the total Lower-48 gas resource base is in Alaska. Most of Alaska's gas resource is unused and currently unusable due to low state demands and lack of a system to transport gas outside the state.

Alaska gas is the only U.S. gas resource that could be developed for export without compromising the U.S. supply and demand scenario or increasing costs to the U.S. consumer. Alternative development of Alaska gas for U.S. consumption is not economic at this time, and the "no-development" alternative makes little sense. A feasible alternative for export of Alaska natural gas is liquefaction and shipment as LNG. At this time, the most apparent LNG export market opportunity lies in the Pacific Rim. Japan is the most promising candidate for purchase of U.S. gas; Taiwan and Korea also have market potential.

Supply and Demand for LNG in Japan: Six nations currently supply Japan's demand for LNG. A total of 26.7 million metric tons (MMT) were supplied in 1985. Under existing contracts, that amount would decrease to 25.8 MMT in the year 2000 and 5.8 MMT in 2005. Even if existing contracts are renewed, Japan will require additional sources of LNG by the early 1990's. In 1995, the projected shortfall ranges from 3.4 to 1.5 MMT. The shortfall in LNG increases to a range of 11.2 - 5.9 MMT in the year 2000 and 17.3 - 9.1 MMT by 2010. Any one of a number of changes in the projected Japanese energy plan could increase the LNG shortfall beyond these projections.

The TAGS project is a favorable source of supply for projected LNG demand in Japan through the year 2010 and beyond. A significant potential for export to Korea and Taiwan also exists. At full capacity, TAGS could supply 14 MMT of LNG per year, generating approximately $3.0 billion in gas sales. If TAGS supplied only half that much to Japan in the year 2000, the U.S. would receive approximately $1.5 billion. Additional intangible benefits would be realized by reducing the imbalance of trade, decreasing Japan's dependence on foreign competition, and enhancing Japan's relationship with the U.S.

1.0 INTRODUCTION

Feasibility of the TAGS project is affected by local, national and international resources of natural gas. To interpret and compare various resource base estimates, it is important that boundaries of the estimates be defined. Natural gas resources are generally categorized according to the economic and technical feasibility of production as well as geologic certainty of occurrence. There are generally accepted categories of natural gas resources, though there are some variations in the definition and usage of terms.

The finite volume of natural gas existing within the earth's crust comprises the total natural gas resource. A portion of this is "unrecoverable"; that is, never likely to be economically and technologically producible. The "recoverable" portion is considered available for production during the life of industry, using current or foreseeable technology, under favorable economic conditions. Recoverable resources have both a "discovered" and an, as yet, "undiscovered" component.

Of the discovered resources, some have already been "produced"; some have been proved as "reserves" for future production. Reserves are defined as measurable volumes of gas that are commercially recoverable from known fields, by established operating practices, under existing economic conditions.

"Probable resources" are also associated with known fields, but are only estimated quantities of gas, likely to be recovered under existing economic and operating conditions. They comprise one category of "potential" resources. Other potential gas categories are comprised of "possible" and "speculative" resources. Possible potential resources are less assured than probable resources, but are associated with a productive formation in a productive province. Speculative resources are the least assured, but can be the most important in assessing overall potential (Marshall, personal communication, 1987). Speculative resources are expected to be found in formations or provinces not yet proven to be productive.

A long-term assessment of the existing resource base considers both the proved reserves as well as the additional potential resources of an area.

Due to the many parameters involved in resource base assessments (economics, available data, technology, geography, approach, assigned probabilities, degree of optimism, etc.), it is sometimes difficult to compare resource estimates. Secondary factors including supply vs. demand; competitive field prices; new exploration; deliverability; regulatory constraints and incentives; and local, national, and global politics also tend to influence resource evaluations, projections, and perceptions.

It is also important to note that resource base components are not static. Estimates of reserves and potential resources are subject to revision as economic conditions change, as additional geologic and engineering data become available, as exploration and extraction technologies develop, as new discoveries are made, or as reserves are produced. (J. Petroleum Technology, 1987).

For this report, approximately 100 resource assessments were reviewed (55 on Alaska gas resources); the most appropriate assessments and most representative data are presented here in support of the proposed Trans-Alaska Gas System (TAGS).

2.0 ALASKA NATURAL GAS RESOURCES

Alaska is recognized as a storehouse of petroleum wealth. Recent estimates indicate that proved natural gas reserves in Alaska equal approximately 20 percent of the total proved gas reserves in the Lower-48 states (USDOE, 1987; PGC , 1987; USDOE, 1984; Comm. on Energy and Nat. Res., 1984). Potential gas resources in Alaska may also equal up to 20 percent of the total potential resources in the Lower-48 (PGC, 1987; USGS, 1981).

Alaska gas reserves are included in about 27 separate accumulations; approximately 88-92 percent of the total reserves are located in the North Slope oil and gas province (PGC, 1987; ADNR, 1987; AOGCC, 1987; Comm. on Energy and Nat. Res., 1984). The largest accumulation is in Prudhoe Bay (ADNR, 1983). The Prudhoe Bay field contains the largest accumulation of oil and gas ever discovered on the North American continent (FERC, 1980a). The vast majority of reserves are found in the Prudhoe Oil pool. Other gas reserves near the Prudhoe Oil pool are found in Lisburne, Kuparuk River, Endicott, and Pt. Thompson.

A recent federal study concluded there are 36.5 trillion cubic feet (TCF) of known gas resources that exist in and near the Prudhoe Bay area (Young and Houser, BLM, 1986). However the State of Alaska is considered to be the best source of local reserve assessments as agencies have access to the most up-to-date information; both published and privileged resource data are considered in estimating natural gas reserves. Current State of Alaska estimates of recoverable gas reserves range to 37.0 TCF for the same area (ADNR, 1987). Over the last few years, state estimates of gas reserves in the Prudhoe Bay area have ranged to 39.4 TCF (ADNR, 1984, 1985, 1986a). It is stated in the State of Alaska 1985 Energy Plan that "it is possible, with 40 TCF of gas on the North Slope, that LNG could be shipped to the Pacific Rim nations and natural gas piped to the South-48" (ADCED, 1984).

In addition to gas reserves, potential gas resources exist on the North Slope and adjacent offshore areas. Current estimates of potential gas in those areas range from a mean of 97 TCF to a high of 304 TCF (PGC, 1987). Earlier USGS estimates of undiscovered recoverable natural gas resources range to 216 TCF for Alaskan arctic regions (USGS, 1981).

Recently, state and federal studies have identified additional gas resources in the Arctic National Wildlife Refuge (ANWR). The BLM estimated there are 31.3 TCF of natural gas in-place in ANWR (USDOI, 1987). Using a conservative recoverability factor, it was recently estimated that up to 23 TCF could be recoverable gas resources (Marshall, personal communication, 1987). The National Petroleum Reserve (NPR) has also been an area of special study. Recent estimates of undiscovered gas in place range from 2.4 to 27.2 TCF, with a mean estimate of 11.3 TCF (USGS, 1985). Using the same conservative recoverability factor used for ANWR, an estimated 8.5 TCF could be recoverable in the NPR. Other new or undefined potential resources exist in Alaska (e.g., Seal Island, Northstar Island, Gwydyr Bay, Corona, Hammerhead) that may not have been included in previous estimates. In addition, new areas are continually being leased for exploration by state and federal agencies.

To date, only a small percent of the Alaska mainland and offshore areas have been leased or developed, but federal and state programs are in place to facilitate future lease sales. For example, the state, in response to the legislature's finding that "the people of Alaska have an interest in the development of the State's oil and gas resources," has developed a five year oil and gas leasing program for the period 1987 to 1991. To encourage leasing, the State is authorized to employ leasing methods involving cash bonuses, royalties, and net profit shares. Exploration incentive credits are authorized to encourage frontier exploration. (ADNR, 1986b). Federal agencies have similar long-range plans for leasing federal lands and offshore areas for oil and gas exploration, development, and production.

In 1985, thirty-five exploratory wells were active in Alaska, with thirty-two completed during the year. This fell only three wells short of the 1966 record of thirty-eight active exploratory wells. One new field discovery (Colville Delta) was announced in 1985. However, due to a variety of factors, a dramatic decrease was anticipated for 1986. (Steenblock, 1986). New or improved markets for oil and gas would likely encourage a resurgence in exploration for Alaska petroleum resources.

There is another reason to encourage new petroleum market developments in Alaska. With the Prudhoe Bay oil production expected to drop continuously after 1988, new resources will be required for Alaska to offset the reduction in royalty income to the state. Presently, natural gas produced during oil production is reinjected and not available for commercial use.[1] Existing natural gas resources and potential discovered and undiscovered gas resources could help the State of Alaska offset the decline in oil production. (ADNR, 1986b; ADCED, 1985).

Production of natural gas for intrastate transportation and shipment of LNG to foreign markets would have little impact on local or national energy resources. It would however, enhance national security, contribute to the national campaign to level the balance of trade with Pacific Rim countries, as well as provide substantial benefits to the State of Alaska.

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[1] In 1986, of 1.4 TCF of gas produced in Alaska: 1.1 TCF were reinjected; approximately .1 TCF was used in field operations (.007 TCF were vented/flared); and approximately .2 TCF were sold (ADNR, 1987).

3.0 U.S. NATURAL GAS RESOURCES/GAS INDUSTRY

The current outlook on U.S. natural gas resources is generally optimistic. The director of the Potential Gas Agency reports there is more conventional natural gas left to be discovered in the United States than has been produced throughout the entire history of the U.S. gas industry. Recent gas discoveries have opened up new frontiers that will eventually add significantly to the U.S. resource base (AGA, 1987b). Under all reasonable energy price scenarios, there will be a steadily increasing supply of U.S. natural gas through the year 2010, predicts the chairman of the American Gas Association (AGA) Gas Supply Committee. In addition, improvements in drilling and production technologies could open up new resources not yet considered by the Committee in forecasting gas supplies. AGA President, G. H. Lawrence, reports that currently producing unconventional gas resources add about 200 years of supplies (AGA, 1987b). According to Henry Linden, past president of the Gas Research Institute (GRI), technological developments in secondary gas recovery could improve domestic production capability by one-third by the year 2010; some additional production could be expected as early as 1990. (AGA, 1987a).

These projections mark a change in direction for the U.S. gas industry. Through the mid 1980's, the gas industry has developed and operated in an environment characterized by "shortage." However, the U.S. natural gas industry is undergoing a significant transition. Recent developments are stabilizing the industry environment and working to assure a long-term, economical gas supply to meet domestic needs.

3.1 U.S. Natural Gas Resources

The domestic gas resource base is substantial. The U.S. ranks third in the world for proved reserves, with 190 TCF the most current average estimate (IGT, 1987b; USDOE in IGT, 1987c; AGA, J. Wiggenroth, personal communication, 1987; PGC, 1987; Aalund, 1986). Estimates of potential gas are a little more variable, but the most accepted appears to be 739 TCF of conventional resources (PGC, 1987). Other estimates of potential conventional resources range to 900+ TCF (OTA, 1985) and 1,200 TCF (MMS, 1983). Estimates including unconventional gas resources go even higher. Some estimates of potential gas from unconventional resources alone range over 1,900 TCF (cited in MIT, 1985, p.56; Commoner, 1983, pg. 86). It is clear that an insufficient domestic resource base was not the cause of shortages historically experienced in the U.S. gas industry and gas market.

3.2 U.S. Gas Industry

The gas industry and associated market is controlled not only by the resource base, but also by a variety of often complex, often interrelated, factors. Both intrinsic and extrinsic controls tended to keep the gas industry highly structured and regulated for more than 30 years. Then, in the 1970's, two major energy crises forced the world to carefully assess fuel market dynamics -- at both national and international levels. Subsequent changes in science and technology, changes in perception, and changes in regulation have loosened some of the controls and may well allow -- even encourage -- natural gas to develop its potential among competing fuel sources in the energy marketplace.

Development of the TAGS project is consistent with continued development of the U.S. natural gas industry. Development of TAGS will enable the U.S. to maximize use of a large, currently untapped natural resource -- North Slope Alaska gas. In addition, TAGS will likely encourage further gas exploration, advance associated technologies, establish infrastructure for future gas supply projects, create fuel-switching options both locally and abroad, and increase the overall energy security of the U.S. and its allies.

As exploration expands, technology advances, and established infrastructure increases marketability, the gas resource picture will change. It is likely that new gas resources will be indentified; the assurance of existing potential resources will likely increase. As the stock of "proven" reserves is based on economics and technology, it is also likely that more gas will be added into this category.

Reserve additions have been down in recent years, reflecting reduced exploration and development activity in the U.S. This, in turn, is a reflection of lowered prices, lowered demand, and excess production capability.

In the U.S., the supply, demand, and cost of natural gas is highly dependent on competing fuel market conditions, particularly the availability and cost of oil. Generally, as the price of oil goes down, the price of gas also decreases, along with the incentive for exploration and development. When new reserves are not added at a rate equal to existing production, the total supply of reserves is depleted. In addition, when the existing production capability exceeds demand, a surplus deliverability develops and keeps prices depressed.

The overall scenario is complex, with other factors intervening (e.g., regulations, industry attitudes, fuel-switching capabilities, existing practice and infrastructure, international economics, import potential, and protectionism). It is believed that TAGS will positively affect some parameters controlling the gas industry and U.S. energy security without reducing the supply of natural gas available to U.S. consumers or increasing the cost. The following information is presented in support of this statement.

3.3 U.S. Gas Supply and Demand

Natural gas has been an important source of energy in the United States. In 1970, natural gas consumption accounted for approximately 32 percent of total domestic energy use. However, between 1970 and 1985, relative gas use dropped to about 24 percent of the total energy use. It is projected that relative dependence on natural gas for energy will continue to drop to an average 20 percent of total use by the year 2000. (USDOE, 1986).

Total U.S. gas supply peaked in 1972 at about 22 TCF. Of this, approximately 21 TCF were produced in the U.S. and approximately 1 TCF was imported from Canada (NEB, 1986). However, low regulated prices on U.S. production and National Energy Board restraints on expanding Canadian exports to the U.S. resulted in a U.S. supply of just under 20 TCF in 1975. U.S. supplies stayed at about this level through 1981 as price ceilings increased, leading to exploration and development of U.S. resources as well as increased availability of Canadian gas in the markets. The increased level of exploration led to significant reserve additions in 1981 and 1982. However, the early 1980's also brought reductions in industrial gas use, energy conservation, and fuel-switching that resulted in reduction of the gas demand to about 17 TCF in 1985.

Despite the lowered demands of the 1980's, the total supply capability established earlier remained in excess of 20 TCF. With supply capability exceeding demand, financial incentive for exploration deteriorated, and reserve additions dropped after 1982. However, excess production capability continued, and by 1985, a significant surplus or "gas bubble" existed. (NPC, 1987; OTA, 1985). The existing gas bubble is expected to last until 1990, according to the AGA. An evaluation of energy markets by ICF Inc., a Washington-based consulting firm, is reported as saying that a significant surplus of gas production capacity in the U.S. will probably last well into the 1990's (IGT, 1987a). Table 1 presents various agency estimates of surplus gas production capability in the U.S.

Table 1

Estimated Surplus U.S.Production Capability in 1985

(TCF)

Department of Energy	3.0 - 4.6*
Gas Research Institute	2.0 - 2.5
American Gas Association	3.6

* Dependent on time of year.

(USDOE, 1986; GRI,1986)

Changes in the gas market brought about changes in gas economic regulations, but they were not able to keep gas prices from dropping as planned. The 1986 drop in oil prices also depressed gas prices, further discouraging domestic exploration and developments in support of future gas supplies. It is projected that, at prices competitive with alternate fuels, U.S. production using established base technology will decline going into the 1990's.

Table 2 presents a summary of three agency projections of U.S. natural gas supply and demand to the year 2000 and beyond, based on 1985 statistics as presented.

To match projected demands, supplementary supplies will likely be required. There are a number of options that have the potential to provide gas supplies to meet U.S. domestic demand. These include: increasing conventional supplies (e.g., through cost incentives, further exploration, and/or advanced technologies); developing unconventional supplies; and expanding imports.

3.3.1 Increasing Conventional Supplies

The existence of a "gas bubble" tends to mask fundamental economics of gas supply and may provide little incentive for further exploration and development. However, it is predicted that as the current surplus deliverability diminishes, demand for gas will lead to the orderly resumption of producer activity.

Table 2

U.S. Natural Gas Supply and Demand
(TCF)

		1985		1990		1995		2000		2010	
		SUP	DEM	SUP	DEM	SUP	DEM	SUP	DEM	SUP	DEM
DOE	DGP	16.4a		16.90		16.6		16.12			
	IMP	.9		1.05		1.8		2.43			
	I&O	.3		.0		.2		.0			
	Total	17.6	17.3	17.95	17.5	18.6	18.04	18.55	17.92		
NPC	DGP	16.4		15.5-16.4		13.3-15.2		12.4-14.5			
	IMP	.9		1.5- 1.3		2.2		2.6			
	I&O	NI		<0-.1>		<0-.1>		<0-.1>			
	Total	17.3	17.3	17.0-17.6	17.3-17.6	15.5-17.3	16.20-17.40	15.0-17.0	15.1-17.2		
GRI*	DGP	16.1		16.1				16.3		13.3	
	IMP	.9		1.0				2.0		3.3	
	I&O	.8		.4				.8		2.4	
	Total	17.8	17.3	17.5	16.9			19.1	18.5	19.0	18.4

Notes:

a 16.4 DGP = 17.2 TCF marketed production (wet); updated to 19.9 TCF (wet) in DOE January 1987 Monthly.
NI Not Indicated in the referenced literature.
DGP Dry Gas Production
IMP Imported Gas
I+O Inventory Change and Other Supplies
+ Ranges in supply and demand reflect low to high price ranges of oil.
* Data originally in quadrillion Btus; converted using 1030 Btu/cf (NPC, U.S. Oil and Gas Outlook 1986)

Data References

DOE Department of Energy, Annual Energy Outlook 1986 With Projections to 2000, DOE/EIA, 1986.

NPC National Petroleum Council, "U.S. Oil & Gas Outlook", An Interim Report of the National Petroleum Council, October 1986.

National Petroleum Council, "Factors Affecting U.S. Oil & Gas Outlook, February 1987.

GRI Gas Research Institute, 1986 GRI Baseline Projection of U.S. Energy Supply and Demand to 2010, December 1986.

Indicators of a tightening supply often raise the level of consciousness about energy security.

Generally, as the value of a secure supply goes up, prices go up, and producers are encouraged to invest in exploration, development, and upkeep of existing facilities. (GRI, 1986). Under this scenario, the U.S. may increase reserves and produce domestic gas at levels higher than projected.

Committing uncommitted nonproducing reserves could fairly quickly increase annual deliverability by 0.25 - 1.0 TCF. In addition, several of the largest gas fields in the country are amenable to infill drilling to increase production capability and proved reserves. (AGA, 1986).

Development of frontier gas projects such as the Alaska Natural Gas Transportation System, (ANGTS) may also fall under this scenario. Timing of these projects will depend on when -- or whether -- a clear need for North Slope gas can be demonstrated in the U. S. marketplace at prices that would support financing of the required infrastructure. The Pacific Alaska LNG project proposed to ship Cook Inlet (Alaska) gas to California has been approved but on hold for eight years, pending favorable U.S. market conditions.

Currently, circumstances discouraging imminent development of frontier gas for domestic use include: surplus deliverability of gas in the U.S.; proven U.S. gas reserves to satisfy demands to the turn of the century; projected lower costs for Lower-48 and imported gas to the year 2010; and apparently adequate supplies of economic gas for import during current projection periods (AK. Dept. of Revenue, 1987; IGT, 1987a; Anchorage Daily News, 1987 GRI, 1986; USGAO, 1983).

Proposals to bring gas from Alaska emerged during the 1970's when parts of the U.S. were experiencing gas deliverability shortages. However, since then, gas supplies have been enhanced and fuel switching has reduced demand. In addition, the potentially high cost of frontier gas appears to render it uncompetitive with other available energy sources. Projections on the cost of ANGTS gas are presented as an example.

In 1983, a federal study calculated the fixed and annual expenses that ANGTS would have to recover and that were not economically avoidable. Using a minimum charge analysis, the initial transportation charge for ANGTS was estimated at $5.25 per thousand cubic feet (MCF). A maximum wellhead price of $2.28 was added for an estimated price of $7.53 per MCF (1982 dollars) for gas on completion of the project in 1989. For comparison in that study, the price for Lower-48 natural gas was projected to be $3.89 per MCF (1982 dollars) in 1990. (USGAO, 1983).

In a 1984 baseline projection, the GRI price estimate for ANGTS gas, based on pipeline cost estimates and revenue requirements was $9.64 per MCF (1983 dollars) for annual deliveries of 0.7 TCF of gas to the Lower-48 in 1990. For comparison, ANGTS gas that year represented the highest cost source of gas, with estimated costs exceeding those of Lower-48 production, pipeline and LNG imports, coal gas, and synthetic gas. (Young and Houser, BLM, 1986; GRI, 1984). More recently, GRI projected that the cost of LNG and coal gas may slightly exceed ANGTS gas by 2010, but that other U.S. produced gas and pipeline inputs would still be available at lower cost in that year. (GRI, 1986).

Since that time, regulation changes, market changes, and inflation have changed the specific cost data, but not the relative cost of ANGTS. At this point, ANGTS is generally considered a marginal source of supply. However, it is estimated that by the time the U.S. gas market can support an ANGTS supply, sufficient gas resources should be available (Young and Houser, BLM, 1986; ADNR, 1984, 1985, 1986a, 1987).

3.3.2 Developing Unconventional Supplies

A general consensus of "conventional" forecasts indicates that the surplus in natural gas supply will last for several years, accompanied by lowered production, and eventually increasing prices. Forecasting unconventional gas supplies is more complex.

It is difficult to project the type and volume of gas that might be producible outside the framework of today's technology and today's economy. To avoid this dilemma, many forecasts consider what would be available with existing technology. By this measure, approximately one-fifth of current gas production would have been defined as "unconventional" 35 years ago.

In 1985, the Massachusetts Institute of Technology (MIT) cited a forthcoming projection that unconventional gas could provide as much as one-third of the total gas supply by 2010 (MIT, 1985). In 1980, the National Petroleum Council (NPC) reported that up to 4.2 TCF per year of gas from tight sands alone could be provided by 1995, under a feasible price scenario. (NPC, 1987; OTA, 1985; Schantz and Foster, 1982).

In 1987, the Potential Gas Committee (PGC) reported on U.S. gas resources that may be recoverable from coal seams. Based on research and production testing, the PGC actually considered coalbed methane to be a "conventional" resource for the first time. Preliminary PGC estimates placed coal-bed methane in-place resources in the range of 400 to 800+ TCF. A complete quantitative estimate of recoverable gas was not provided. In a limited study, the PGC estimated that about 45 TCF of coalbed methane were most likely recoverable from thirteen representative coal-bearing basins in the U.S. Reference was also made to previously published estimates by others of recoverable coalbed methane ranging to 487 TCF. (PGC, 1987). The importance of this resource is growing and needs to be carefully considered in projecting future U.S. supply potential.

At present, the role of unconventional gas (e.g., gas from tight formations, deep gas, and methane from hydrates), remains difficult to quantify. However, consideration of estimates of unconventional U.S. gas resources that range to more than 1900 TCF (cited in MIT, 1985, p. 56; Commoner, 1983, p.86), indicate that a potentially strong component of tomorrow's gas supply may come from today's "unconventional" resources.

3.3.3 Expanding Imports

Historically, Canada has been the largest supplier of gas imported by the United States, providing gas in accordance with U.S. needs for over thirty years. Canada is a close ally; the Canadian gas supply is considered secure, reliable, and plentiful. Estimates of proved reserves average 100 TCF, ultimately recoverable resources have been estimated to 420 TCF, and development of unconventional resources would considerably increase this resource base. (USDOE, 1987; Puziene, 1987; NEB, 1986; OTA, 1985). Even at low gas prices, additional Canadian gas imports are considered economically viable (AGA, 1986).

Currently, import of Canadian gas is limited by U.S. market conditions. In 1986, less than fifty percent (about 0.75 TCF) of that authorized was actually imported by the U.S. Demand for Canadian gas is not expected to increase significantly in 1987 (Petroleum Economist, 1987); it may decrease. Existing gas contracts could support levels of Canadian imports to about 1.9 TCF per year. About 1.5 TCF per year could be imported without additional construction; greater delivery rates would require some construction (Puziene, 1987; AGA, 1986).

Applications for 1.9 to 2.2 TCF of additional pipeline capacity for export of Canadian gas to U.S. markets have already been filed with the Canadian National Energy Board (NEB) and the Federal Energy Regulatory Commission (FERC). Several of these projects are on hold until export economics improve. Two notable examples are the Polar Gas project, proposing to export gas from the Mackenzie Delta/Arctic Islands and the Venture gas project, proposing to export gas from offshore Nova Scotia. Together, these two projects could export up to 0.4 TCF per year to the U.S. (Puziene, 1987).

Production costs for Canadian reserves are relatively low with much of the support system already in place (sunk costs). Some gas wells have been shut in and could be producing at wellhead prices only marginally above operating costs. (AGA, 1986). Softening of the U.S. import market, coupled with only slight increases in

Canadian consumption, has held Canadian production at lower rates than possible or preferable (Stoneman, 1986). Currently, Canada is experiencing a gas bubble of 1.5 - 2.0 TCF (Pan-Alberta Gas Ltd., 1987). More gas could be produced if the demand were increased. In 1985, productive capacity of natural gas from all Canadian sources was approximately 4.5 TCF (NEB, 1986); actual production was much lower.

In 1985, approximately 2.9 TCF of gas were produced in Canada. Of this, approximately 2.0 TCF supplied Canadian demands, and .9 TCF was exported to the U.S. Projections of future Canadian demand show some consistency, with NEB forecasts fairly representative of those published by the Journal of Petroleum Technology and the U.S. Department of Energy (USDOE). Currently, NEB projects Canadian gas demand to be: 2.2 TCF in 1990; 2.3 - 2.6 TCF in 1995; 2.5 - 2.8 TCF in 2000; and 2.8 - 3.1 TCF in 2005. (Puziene, 1987; USDOE, 1987; NEB, 1986).

Projections of future production rates vary, based on a number of factors including perceived reserves, U.S. and Canadian markets, and government support for exporting natural gas. Currently, reserves are over 30 times the annual production rate, a ratio three times that of reserves to production in the U.S. This is unquestionably a comfortable margin, even in Canada where the NEB requires a gas surplus reserved to meet reasonably foreseeable

Canadian requirements. If Canada were producing only to meet domestic demand, the ratio would be more on the order of 50 to 1, suggesting a 50 year domestic supply at existing rates of consumption.

It is not, however, reasonable to assume that such a static situation will exist. Annual domestic demand is projected to increase to an average 2.6 TCF by the year 2000 and approximately 3.0 TCF by the year 2005 (Puziene, 1987; NEB, 1986; MIT, 1985). Reserve additions will balance some, if not all, the depletions over the next 20 years. In the past 20 year period (1965 to 1985), reserve additions increased the pool of Canadian gas reserves more than 75 TCF. However, there is always uncertainty associated with predicting reserve additions. Two current estimates of reserve additions over the next 20 years are 35 and 39 TCF (Puziene, 1987; NEB, 1986). Prevailing economic conditions and technological progress could substantially increase those estimates.

In considering domestic Canadian demand projections and even conservative estimates of proved and probable gas reserves, it seems safe to conclude that factors <u>other</u> than the amount of "exportable surplus" will control exports to the U.S. (MIT, 1985). Canadian production levels will be a critical factor.

Estimates of Canadian production over the next twenty years vary, depending, in part, on the volume projected for export. NEB projections show about 1.4 TCF available for export in 1990.

According to their 1985 projections, the volumes available for export would then decrease continuously through the turn of the century. However, several U.S. projections show over 2.0 TCF potentially available in 1990 (Puziene, 1987; OTA, 1985). For the year 2000, U.S. projections of Canadian gas for export to the states range to highs of 2.1 - 3.0 TCF (NPC, 1987; GRI, 1986; OTA, 1985). A recent assessment of the more pessimistic NEB projection indicates the Canadians may have overstated production (and consequently gas exported) in the late 1980's and early 1990s, which would ultimately understate the amount available for export later in the projection period. In addition, the NEB projection does not appear to include deliverability from frontier area reserve additions, an omission which also lowers the projected volume producible. Adjustment to accommodate these two factors would increase the amount available for export after 1990. (Puziene, 1987).

There is currently enough capacity in Canada's gas supply system to increase production to 4.0-4.5 TCF, which would permit export levels of about 2.0 - 2.3 TCF per year. The inventory of Canadian gas is large enough to support production at those levels, and new support facilities are planned. Export of gas is economically important to Canadian producers. The need to develop new or expanded gas markets is being fueled by the large supply base, price reductions, and lowered export demand in recent years. (NEB, 1986;

Stoneman, 1986). In addition to projects advancing U.S. export potential, the Western Canada LNG project (formerly Dome LNG) recently proposed to export up to 0.16 TCF a year, for twenty years, to Japan (Wall Street Journal, 1984).

Recent decisions by the NEB underscore the importance of export to the Canadian gas industry. In September, 1987, the NEB adopted new natural gas surplus determination procedures. The government felt that the previous Reserves/Production Ratio (15/1) Procedure could lead to greater restrictions in export volumes than would be warranted by public interest. The newly adopted procedure is based on the premise that the marketplace should determine the supply, demand, and price of natural gas. (NEB, 1987a, 1987b). It is expected that the new ruling will prompt substantial exploration (Anchorage Times, 1987). With Canadian gas industry support and, now, significant government support, Canada must be considered a viable source of natural gas to meet U.S. demands in the future.

Canada, however, is not the only potential source of gas for import into the U.S.; Mexico also holds an important position in the world energy resource base. As with Canada, domestic gas reserves will not be a production constraint for Mexico. Based on current reserve figures, considerable expansion in natural gas production is feasible. Several 1986 estimates of Mexican reserves yield an average of 77.0 TCF (USDOE, 1987; DeGolyer and MacNaughton, 1986). Earlier estimates by the Mexican government have included 114 TCF of natural gas reserves, with an additional 345 TCF potentially available (MMS, 1983). Although official reserves data do not show it, it is viewed by some within the industry that Mexico's ultimate hydrocarbon potential may be very close to Saudi Arabia's (Tussing, 1984).

There is some variance in Mexican production figures, with 1.0 TCF and 1.3 TCF reported for 1985 by the USDOE and the Oil and Gas Journal (OGJ) respectively (USDOE, 1987; Aalund, 1986). The difference may be due to processing losses; nonetheless, the volume is small by comparison to reserves. The current reserves to production ratio is approximately 60 to 1, which gives a good indication of how much Mexican gas production could be increased (AGA, 1986). Based on projection methods used in an earlier study (USGAO, 1980) and current reserve statistics, it is estimated that up to 4.0 TCF of gas could be produced in association with oil production (at capacity). Development of the substantial resource of non-associated gas could further increase the gas production capability of Mexico (OTA, 1985). The previously stated estimate of current production (1.0 - 1.3 TCF per year) is limited by domestic demand, national economics, and exportability.

Much of the gas currently produced in Mexico is used to meet domestic needs; some is reinjected; some is flared. From 1980 to 1984, an average 0.2 TCF of gas per year were vented and flared in Mexico (IGT, 1987d). The national policy of Mexico is to use natural gas to meet domestic energy needs and export other kinds of energy resources. Mexico has been successful in encouraging conversions to natural gas within the country; gas demand has been growing at 13 percent per year. (OTA, 1985). Factors exist, however, to limit future growth at such a rate.

Mexico's financial condition has precluded investment in distribution equipment. Mexico's near-default in loan repayment in mid-1982 shook the international financial community (Tussing, 1984). Many policymakers believe energy exports are necessary to bolster Mexico's ailing economy (OTA, 1985). An incentive is seen for Mexico to increase gas exports to help balance inadequate oil revenues and contribute toward stabilization of national income.

The U.S. has been importing Mexican gas for approximately thirty years. In 1977, the government-owned petroleum monopoly, PEMEX, signed an agreement with six U.S. pipeline companies to export 2 BCF per day (0.7 TCF per year). A breakdown in price negotiations with the U.S. led to a shift in direction, and Mexican gas imports by the U.S. were temporarily curtailed. In late 1979, the U.S. and Mexico agreed upon terms and signed a new agreement for 300 MMCF per day. The lowered amount reflects successful implementation of the Mexican national plan to increase domestic use of gas during the interim. Gas imports by the U.S. resumed in 1980. Early in 1982, the Mexicans proposed increasing their export capability to 500 MMCF per day and later to 1000 MMCF per day (0.4 TCF per year). However, lack of collection infrastructure, along with budget cutbacks and uncertainty over near-future potential, curtailed these expansion plans for the time being. In 1984, gas imports by the U.S. were suspended again due to falling U.S. gas prices.

U.S. gas imports could likely be reinstituted without much delay. In Texas, near the point of import, there are five major U.S. pipelines in place; a major Mexican pipeline comes close to the U.S. terminals on the other side of the border. Facilities could be modified to handle greater gas volumes with relative ease. (AGA, 1986).

Estimates regarding the quantity of Mexican gas available for future export vary. AGA estimates reported in a recent U.S. government study range from approximately 0.1 to 1.5 TCF by the year 2000 (OTA, 1985). Earlier (1980) projections by the U.S. Congressional Research Service also show Mexican imports ranging to 1.5 TCF, as early as 1988. At that same time, the U.S. Comptroller General projected that Mexican imports to 2.0 TCF per year might be possible by 1985. (USGAO, 1980). Although the timing estimate for the latter two projections is obsolete, the large current reserves and extensive reinjection program still support the position that significant gas imports to the U.S. could be accommodated without diverting gas needed for domestic use. Therefore, Mexico must also be considered a viable source of natural gas to meet U.S. demands in the future.

There is yet a third feasible option for importing gas to meet U.S. demands should the need arise. That option involves importing liquefied natural gas (LNG) from almost any LNG resource base in the world. An LNG resource base can be any large reserve where location or logistics have left substantial gas resources uncommitted to existing markets. In 1986, world gas reserves were estimated at 3,406 TCF (DeGolyer and MacNaughton, 1986) and 3,626 TCF (USDOE, 1987). Based on previous data, it is reasonable to estimate that more than 1,000 TCF of these gas reserves are surplus. Most of the surplus gas is located in the U.S.S.R. and the Middle East; Algeria also has carried a significant surplus in the past (OTA,1985). However, though reserves are plentiful, relatively high process and transportation costs may limit the amount of gas made available as LNG. Pricing, marketing policy, and politics will have a significant influence on the future of LNG imports. Demand will also be a factor.

In 1970, confronted with natural gas shortages, the U.S. began importing LNG from Algeria to supplement local supplies. The U.S. also considered importing LNG from other countries as well, including Indonesia, Trinidad, Nigeria, Iran, and the U.S.S.R. (Schantz and Foster, 1982). Import of LNG reached a high of 0.25 TCF in 1979. Since then, the U.S. supply situation has changed considerably. By 1985, in the midst of a gas bubble, the U.S. imported only 0.023 TCF of LNG, although existing agreements enabled annual imports up to 0.8 TCF. (NPC, 1986; OTA, 1985).

There are four LNG receiving facilities in the U.S. today; small amounts of LNG have also been trucked in from Canada to New England. Considering that many of the capital costs for receiving facilities are now sunk, and operating costs of some foreign suppliers are relatively low, the price of LNG may achieve parity with other U.S. gas sources in the future. At competitive prices, LNG should continue to be considered a viable supplemental U.S. gas supply source.

The foregoing discussion has focused on U.S. gas supplies and meeting U.S. gas demands. To supplement domestic supplies, the U.S. has been, and is projected to be, an importer of pipeline gas and LNG. Another aspect of the U.S. natural gas industry/market is the export potential. The growing global gas market prompts consideration of U.S. gas exportability. Economic, geographic, and political conditions advance the Pacific Rim as a primary target for U.S. gas exports.

4.0 EXPORTING U.S. NATURAL GAS

Exporting U.S. gas is not a new concept. The U.S. is, and has been, in the pipeline gas export business for more than 40 years. For almost twenty years, Alaskan natural gas has been liquefied and shipped as LNG to markets in Japan. Shipments have grown from 0.002 TCF in the first year of operation to approximately 0.055 TCF in 1985 (NPC, 1987). The small amount of LNG exported from

Alaska essentially comprises the U.S. gas export industry today. However, with international trade in natural gas accelerating, this modest role as exporter warrants expansion.

The concept of exporting U.S. natural gas presents two primary questions. One, is there U.S. gas available for export, and two, is there a feasible export market. These questions will be addressed in turn.

To answer the question of availability, it is necessary to look at several aspects of the U.S. natural gas resource including volume, location, and transportability. Currently, the U.S. has about 190 TCF of proven reserves - gas that is commercially recoverable by conventional practice under today's gas market conditions. Under other circumstances, considerably more U.S. gas might be available. Conservative estimates show 739 TCF of potential gas from conventional resources only. If sources considered unconventional today were also considered, the U.S. gas resource potential increases by many hundreds of trillion cubic feet. It is reasonable, then, to suggest that there is enough gas in the U.S. market to consider export if market conditions were encouraging.

As noted, volume of gas is one aspect of availability; location and transportability are others. Approximately 20 percent of the proven total U.S. gas reserves are in Alaska; approximately 20 percent of the potential resources are also located there. Alaska in-state gas use is only about 0.24 TCF per year, and there is currently no transportation system to take Alaska natural gas to the Lower-48. Most of the substantial gas resource in Alaska is unused, and in fact, unusable by virtue of its unavailability to potential users outside the state.

Most natural gas is transported via pipeline. This is generally the most economically feasible, practical mode of gas transportation; however, there are exceptions. Transport of Alaska gas via pipeline to users in the Lower-48 is economically unfeasible at this time and in the predictable future. Export of Alaska natural gas via pipeline to foreign users is also economically, and in most cases, technologically, unfeasible at this time.

A feasible alternative for transport of Alaska natural gas is liquefaction and shipment of LNG. With none of the geographical constraints imposed on pipeline transport, liquefied Alaska natural gas could potentially serve any market equipped with LNG receiving facilities. As need and economics dictate, Alaska natural gas could be available. TAGS is proposing to export up to 14 million tons (MMT) per year of Alaska North Slope gas to the Pacific Rim. A project to export 1.3 MMT per year of Cook Inlet gas to Japan has also been proposed (Chappell, 1984).

Alaska gas is the only U.S. gas resource that could be developed for export without compromising the U.S. supply and demand scenario, or increasing cost to the U.S. consumer. Alternative development of Alaska gas for U.S. consumption is not economic at this time, and the "no-development" alternative makes little sense. If conditions change, there appears to be adequate Alaska natural gas to supply both an export operation and a domestic transportation system, as supported by scale economics of proposed pipeline systems.

With the substantial supply of Alaska natural gas ideal for export, the TAGS project will advance U.S. potential to achieve economic and political advantage in the global energy market.

At this time, it appears that the most advantageous market opportunity for U.S. gas export lies in the Pacific Rim. Japan is likely the best candidate for purchase of U.S. gas, with Taiwan and Korea also potential market contenders. A profile of the most promising target market, Japan, follows.

5.0 SUPPLY AND DEMAND FOR LNG IN JAPAN

Six nations are currently contracted to supply Japan's demand for LNG. Under existing contracts, a total of 29.3 million metric tons (MMT) would be supplied in 1990, 28.6 MMT in 1995, and 25.8 MMT in the year 2000. Extension of contracts expiring in this time frame would increase committed supplies to 30.3 MMT in 1990, 34.7 MMT in 1995, and 34.0 MMT in 2000. As shown in Table 3 and Figure 1,

Table 3

Contracted Suppliers for Japanese LNG

Project	Term	Amount Supplied (10^6 Tons) 1985	1990	1995	2000	2005
Alaska	1969-1989	0.96	0.96 *	0.96 *	0.96 *	0.96 *
Brunei	1972-1992	5.14	5.14	5.14 *	5.14 *	5.14 *
Abu Dhabi	1977-1997	2.06	2.06	2.06	2.06 *	2.06 *
Indonesia	1977-2000	7.50	7.50	7.50	7.50	7.50 *
Malaysia	1983-2003	4.57	6.00	6.00	6.00	6.00 *
Indonesia (Badak II)	1983-2003	3.20	3.20	3.20	3.20	3.20 *
Indonesia (Arun II)	1984-2004	3.30	3.30	3.30	3.30	3.30 *
Indonesia (Incrmnt)	1987-1998	-	0.67	0.67	-	-
Australia	1989-2009	-	1.46	5.84	5.84	5.84
Condition A		26.73	30.29	34.67	34.00	34.00
Condition B		26.73	29.33	28.57	25.84	5.84

*Potential Contract Extension

Condition A: Total Potential Supply if all contracts are extended, as indicated (*)

Condition B: Total Committed Supply with no contract extensions

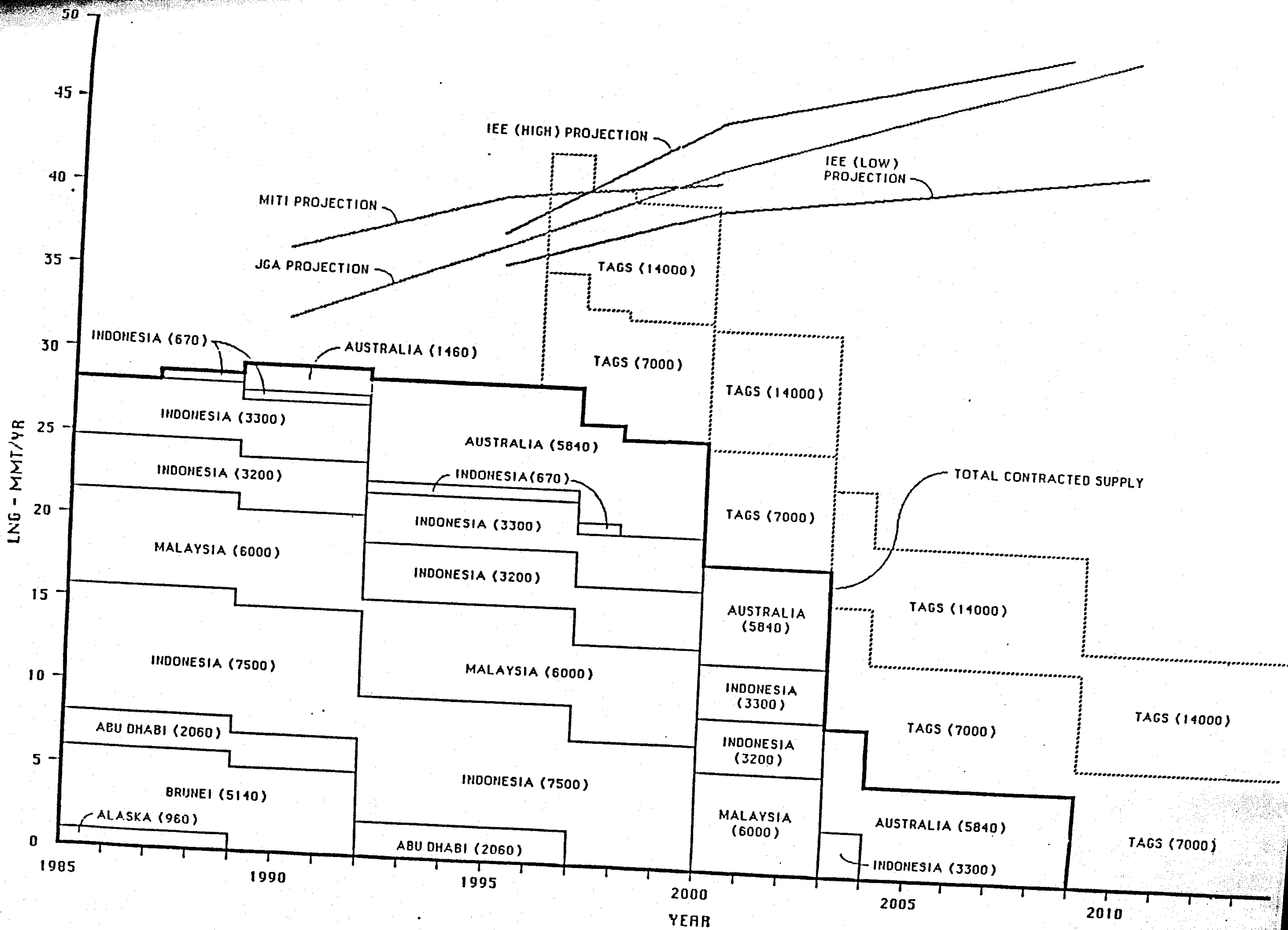

Figure 1. Contracted Suppliers and Projected Demands for LNG in Japan.

Indonesia has the greatest share of Japan's LNG supply market, currently supplying over 50 percent of the demands, and providing as much as 42 percent of total committed supply in the year 2000 if both Indonesian and other contracts are renewed. The United States, the first exporter of LNG to Japan, currently has the smallest market share (3.5 percent), supplying 0.96 MMT from Alaska's Cook Inlet area. This contract is due to expire in 1989. (Japan Gas Assn., 1986; Wright, 1986).

Recent projections show that, even if existing contracts are renewed, Japan will require additional sources of LNG by the early 1990's, as shown in Table 4. The projected demand for LNG in 1995 ranges from a low scenario estimate of 36.2 MMT projected by the Institute of Energy Economics (IEE) in 1987 to 40.0 MMT estimated by the Japanese Ministry of International Trade and Industry (MITI) in 1983. Using only the more conservative 1987 estimates, the projected shortfall for LNG in 1995 ranges from 3.4 to 1.5 MMT. This shortfall in LNG demand increases in the year 2000 to a range of 11.2 MMT to 5.9 MMT, and by 2010 from 17.3 MMT to 9.1 MMT.

Projected shortfalls in LNG would increase beyond these projections if:

1) planned construction of Japanese nuclear power plants is cancelled or delayed;

Table 4

Projected Japanese Demand for LNG (10^6 Tons)

Projection By:	1990	1995	2000	2005	2010	2030
MITI (1983)	36.5	40.0	41.5	-	-	-
Japan Gas Assn. (11/86)	32.6	37.5	42.3	-	-	66.0
IEE Lowest Scenario (5/87)	-	36.2	39.9	41.4	43.1	-
IEE Highest Scenario (5/87)	-	38.1	45.2	48.1	51.3	-

2) the rate of conversion from oil-fired to LNG-fired electric power plants increases;

3) electrical power companies replace planned construction of coal-fired generation plants with LNG-fired plants; or

4) existing LNG contracts are not extended. (See Figure 1).

It should also be noted that potential LNG demand from Korea and Taiwan represents a significant addition to future Japanese requirements.[2] (IEE, 1987).

The TAGS project is a favorable source of supply for projected demand in Japan, and could meet all additional needs for LNG through the year 2010 and beyond. Export of TAGS LNG would have a significant effect on reducing existing trade imbalances between the U.S. and Japan. TAGS would generate a total of approximately $3.0 billion per year in gas sales if 14 MMT/year were sold at $4.00 per MCF. If TAGS supplied 7 MMT to Japan in the year 2000, the U.S. would receive approximately $1.5 billion from Japan.

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2 In early 1987, Taiwan began efforts to seek an additional 1.5 MMT per year supply of LNG, to be imported starting in the 1990's. Korea's most recent government plan indicates need for an additional 3 MMT per year supply of LNG by 1995.

There are additional, intangible benefits to the United States in capturing the future market for Japanese LNG. A combined U.S. supply of 7 MMT from TAGS and 1 MMT from Cook Inlet to Japan would represent approximately 20 percent of the total LNG market, increasing Japan's dependence on the U.S. and decreasing reliance on foreign competition. Other new contenders for future Japanese demand include:

U.S.S.R. (Sakhalin Project)	3 MMT/year
Qatar	6 MMT/year
Thailand	3 MMT/year

Also, Malaysia, Australia, and Indonesia have capacity to expand existing supplies of LNG to Japan.

6.0 SUMMARY

Based on the foregoing discussion, several basic statements can be made regarding the proposed TAGS project and impact on the U.S. natural gas market. They are:

- Alaska has significant gas resources. Even in today's gas economy, the volume of gas classified as reserves closely approximates that needed to support both the TAGS and ANGTS projects.

- Development of gas resources in ANWR and reclassification of other gas resources on the North Slope (once a gas transportation system is in place) would substantially increase Alaska reserves.

- Projected U.S. demand for gas can be economically met with supplies from the Lower-48, supplemented by imports, without development of a gas supply system from Alaska in the foreseeable future.

- The Alaska gas resource is ideally suited for liquefaction and shipment as LNG.

- An export market in Japan and other Pacific Rim countries will exist in the early 1990's.

- The U.S. would gain both economic and political advantages by exporting natural gas to allies in the Pacific Rim.

All of these statements support the TAGS project as proposed by Yukon Pacific Corporation.

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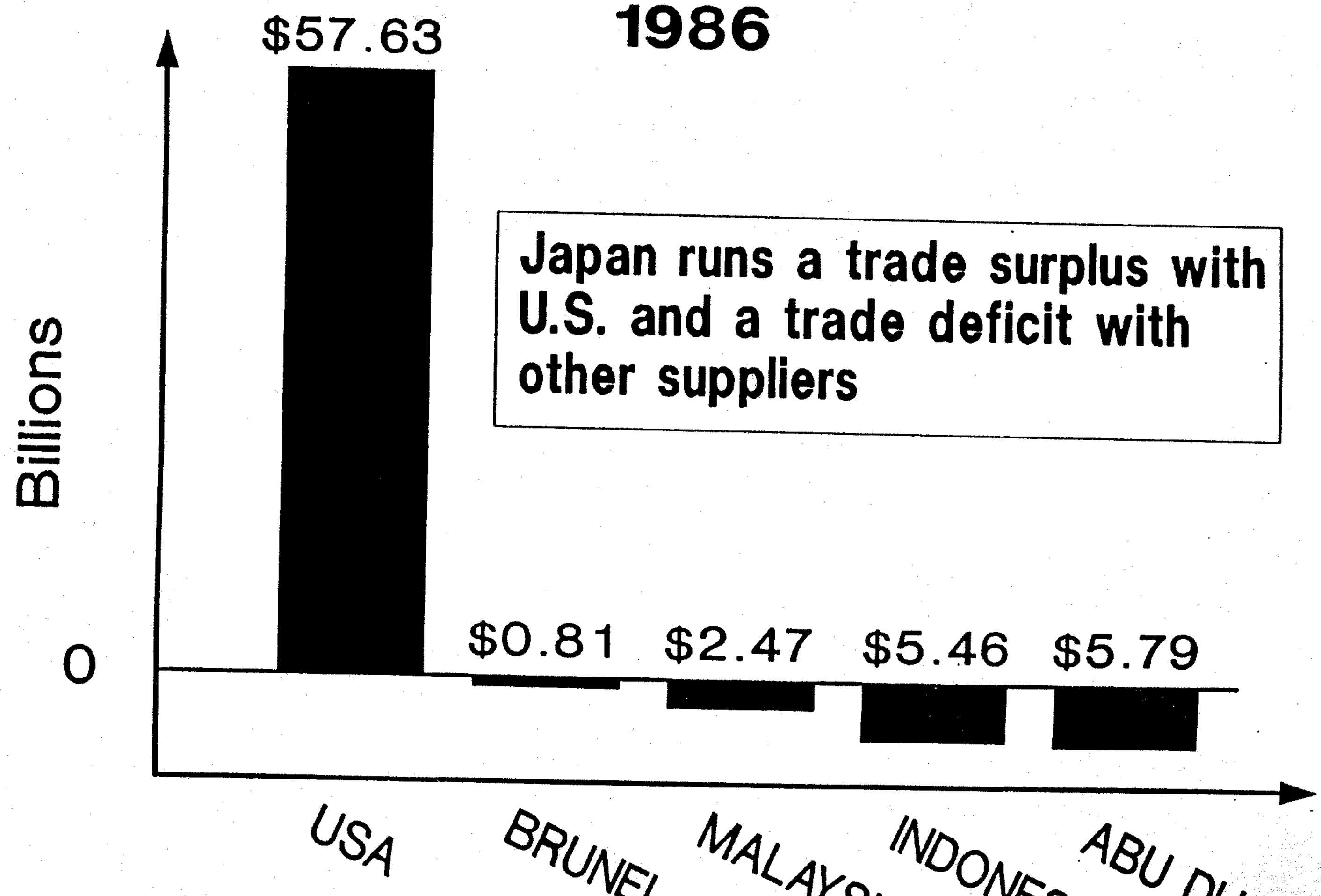
JAPAN'S OVERALL TRADE WITH LNG SUPPLIERS 1986



*Source: Embassy of Japan

YUKON PACIFIC CORPORATION

TRANS-ALASKA GAS SYSTEM

P.O. BOX 101700
ANCHORAGE, AK 99510
900 W. FIFTH AVENUE
ANCHORAGE, AK 99501

APPENDIX CC

Route map for proposed
36" OD. Pipeline

[See Roll #6]

THIS PAGE CONTAINS PROPRIETARY OR TRADE SECRET INFORMATION THAT IS CONFIDENTIAL TO THE PORT AUTHORITY, WHO REQUESTS THAT THE INFORMATION BE KEPT CONFIDENTIAL AND EXEMPT FROM PUBLIC DISCLOSURE TO THE EXTENT PROVIDED IN AS 43.90.150 & AS 43.90.160

Appendix CC – Route Map for proposed 36" O.D. Pipeline

AGPA requests confidential treatment of information contained in Appendix CC – Route Map for proposed 36" O.D. Pipeline to its AGIA Application.

The Route Map for proposed 36" O.D. Pipeline marked as Appendix CC to AGPA's AGIA application consists of and contains proprietary information (as defined by AS 43.90.900 (20) and Trade Secrets (as defined by AS 45.50.940 (3)). The Route Map for proposed 36" O.D. Pipeline contains proprietary information and valued intellectual property and release of this information would cause significant damage to AGPA and its project. There is no question that release of the information ". . . would adversely affect the competitive position of the applicant or materially diminish the commercial value of the information to the applicant[.]" AS 43.90.900 (2). Moreover, the information ". . . derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use;" and ". . . is the subject of efforts that are reasonable under the circumstances to maintain its secrecy." AS 45.50.940 (3).

Brief non-confidential summary pursuant to AS 43.90.160:

The information contained in Appendix CC – Route Map for proposed 36" O.D. Pipeline Appendix V consists of detailed drawing of the proposed 36" O.D. Pipeline. Please note that the Map for proposed 36" O.D. Pipeline does not lend itself to being copied with the proprietary or trade secret information redacted.

APPENDIX DD

Compressor Station A Map
Oversized drawing

[See Roll #1]

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Appendix DD – Compressor Station A map (over-size drawing)

AGPA requests confidential treatment of information contained in Appendix DD – Compressor Station A map (over-size drawing) to its AGIA Application.

The Compressor Station A map (over-size drawing) marked as Appendix DD to AGPA's AGIA application consists of and contains proprietary information (as defined by AS 43.90.900 (20) and Trade Secrets (as defined by AS 45.50.940 (3)). The Compressor Station A map (over-size drawing) contains proprietary information and valued intellectual property and release of this information would cause significant damage to AGPA and its project. There is no question that release of the information ". . . would adversely affect the competitive position of the applicant or materially diminish the commercial value of the information to the applicant[.]" AS 43.90.900 (2). Moreover, the information ". . . derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use;" and ". . . is the subject of efforts that are reasonable under the circumstances to maintain its secrecy." AS 45.50.940 (3).

Brief non-confidential summary pursuant to AS 43.90.160:

The information contained in Appendix DD –Compressor Station A map (over-size drawing) consists of detailed drawing of Compressor Station A. Please note that the over-size drawing of Compressor Station A does not lend itself to being copied with the proprietary or trade secret information redacted.

APPENDIX EE

Compressor Stations for Proposed 36" O.D. pipeline

[See Roll # 8]

Appendix EE – Compressor Stations for Proposed 36" O.D. Pipeline

AGPA requests confidential treatment of information contained in Appendix EE – Compressor Stations for proposed 36" O.D. Pipeline to its AGIA Application.

The Compressor Stations for proposed 36" O.D. Pipeline marked as Appendix EE to AGPA's AGIA application consists of and contains proprietary information (as defined by AS 43.90.900 (20) and Trade Secrets (as defined by AS 45.50.940 (3)). The Compressor Stations for proposed 36" O.D. Pipeline contains proprietary information and valued intellectual property and release of this information *would cause significant* damage to AGPA and its project. There is no question that release of the information ". . . would adversely affect the competitive position of the applicant or materially diminish the commercial value of the information to the applicant[.]" AS 43.90.900 (2). Moreover, the information ". . . derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use;" and ". . . is the subject of efforts that are reasonable under the circumstances to maintain its secrecy." AS 45.50.940 (3).

Brief non-confidential summary pursuant to AS 43.90.160:

The information contained in Appendix EE –Compressor *Stations for proposed* 36" O.D. Pipeline consists of detailed drawing of the Compressor Stations for proposed 36" O.D. Pipeline. Please note that the drawing of the Compressor Stations for proposed 36" O.D. Pipeline does not lend itself to being copied with the proprietary or trade secret information redacted.

APPENDIX FF

Yukon River Bridge
Plans/drawings

[See Roll # 9]

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Appendix FF – Yukon River Bridge Plans/Drawings

AGPA requests confidential treatment of information contained in Appendix FF – Yukon River Bridge Plans/Drawings to its AGIA Application.

The Yukon River Bridge Plans/Drawings marked as Appendix FF to AGPA's AGIA application consists of and contain proprietary information (as defined by AS 43.90.900 (20) and Trade Secrets (as defined by AS 45.50.940 (3)). The Yukon River Bridge Plans/Drawings contain proprietary information and valued intellectual property and release of this information would cause significant damage to AGPA and its project. There is no question that release of the information ". . . would adversely affect the competitive position of the applicant or materially diminish the commercial value of the information to the applicant[.]" AS 43.90.900 (2). Moreover, the information ". . . derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use;" and ". . . is the subject of efforts that are reasonable under the circumstances to maintain its secrecy." AS 45.50.940 (3).

Brief non-confidential summary pursuant to AS 43.90.160:

The information contained in Appendix FF – Yukon River Bridge Plans/Drawings consists of detailed drawing of the Yukon River Bridge. Please note that the Plans/Drawings of the Yukon River Bridge Plans do not lend themselves to being copied with the proprietary or trade secret information redacted.

APPENDIX GG

LNG Terminal Design/Plan Drawings

[See Roll # 10]

THIS PAGE CONTAINS PROPRIETARY OR TRADE SECRET INFORMATION THAT IS CONFIDENTIAL TO THE PORT AUTHORITY, WHO REQUESTS THAT THE INFORMATION BE KEPT CONFIDENTIAL AND EXEMPT FROM PUBLIC DISCLOSURE TO THE EXTENT PROVIDED IN AS 43.90.150 & AS 43.90.160

Appendix GG – LNG Terminal Design/Plan Drawings

AGPA requests confidential treatment of information contained in Appendix GG – LNG Terminal Design/Plan Drawings to its AGIA Application.

The LNG Terminal Design/Plan Drawings marked as Appendix GG to AGPA's AGIA application consists of and contains proprietary information (as defined by AS 43.90.900 (20) and Trade Secrets (as defined by AS 45.50.940 (3)). The LNG Terminal Design/Plan Drawings contain proprietary information and valued intellectual property and release of this information would cause significant damage to AGPA and its project. There is no question that release of the information ". . . would adversely affect the competitive position of the applicant or materially diminish the commercial value of the information to the applicant[.]" AS 43.90.900 (2). Moreover, the information ". . . derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use;" and ". . . is the subject of efforts that are reasonable under the circumstances to maintain its secrecy." AS 45.50.940 (3).

Brief non-confidential summary pursuant to AS 43.90.160:

The information contained in Appendix GG – LNG Terminal Design/Plan Drawings consist of detailed drawings of the LNG Terminal. Please note that the drawings of the LNG Terminal Design/Plan do not lend themselves to being copied with the proprietary or trade secret information redacted.

APPENDIX HH

FERC letter granting extension of
Time to Commence Construction
Of Anderson Bay LNG export facilities
May 18, 2007

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

May 18, 2007

OFFICE OF ENERGY PROJECTS

In Reply Refer To :
OEP/DPC/CB-1
Yukon Pacific Company, L.P.
Docket No. CP88-105-000
§ 375.308(w)(4)

Patrick C. Rock
Attorney-at-Law
1661 Crescent Place, N.W. , Suite 510
Washington, D.C. 20009

Frank A. Lonegro
VP, Internal Audit & Compliance
CSX Corporation
500 Water Street (C-901)
Jacksonville, FL 32202

Re : Request for an Extension of Time

Dear Mr. Rock and Mr. Lonegro:

This responds to your motion dated March 20, 2007 for a fourth extension of time to commence construction of the liquefied natural gas (LNG) export facilities authorized in this docket.

Condition 12 of the Appendix to the Commission's May 22, 1995 Order in the above docket reads: "Yukon Pacific shall commence construction of its Anderson Bay facilities within three years of the date of the Commission's Order, or shall file a motion to extend this deadline." The last sentence of Ordering Paragraph (A) of the May 22, 1995 Order reads "Construction of the Anderson Bay facilities must commence within three years of the date of this Order." [1]

Yukon Pacific has previously sought three such extensions of time to commence construction . These extensions of time until May 22, 2001 and May 22, 2004 were granted by the Director, Office of Pipeline Regulation by letter orders dated April 17, 1998 and April 13, 2001, respectively. The most recent extension of time, through May 22, 2007, was granted by Commission order of May 6, 2004. [2]

Upon consideration of Yukon Pacific's motion filed on March 20, 2007 for a further extension of time to commence construction of the Anderson Bay LNG export facilities authorized in the above docket, an extension of time until May 22, 2010 is granted. As noted in your motion, Yukon Pacific is obliged to undertake and submit a number of studies for the review and approval of the Director of the Commission's Office of Energy Projects prior to the commencement of construction, and these studies must also account for any changes that have occurred over time.

This action is taken pursuant to authority delegated by the Commission in 18 CFR § 375.308(w)(4).

Sincerely,

J. Mark Robinson, Director
Office of Energy Projects

cc: Public File, Docket No. CP88-105-000
All Parties

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[1] Yukon Pacific Company L.P., 71 FERC ¶ 61,197 (1995)

[2] Yukon Pacific Company L.P., 107 FERC ¶ 61, 110 (2004).

APPENDIX II

Drawing / Plans Showing Bore Hole Locations for Anderson Bay LNG Terminal

[See Roll # 11]

THIS PAGE CONTAINS PROPRIETARY OR TRADE SECRET INFORMATION THAT IS CONFIDENTIAL TO THE PORT AUTHORITY, WHO REQUESTS THAT THE INFORMATION BE KEPT CONFIDENTIAL AND EXEMPT FROM PUBLIC DISCLOSURE TO THE EXTENT PROVIDED IN AS 43.90.150 & AS 43.90.160

Appendix II – Drawing/Plans Showing Bore Hole Locations for Anderson Bay, LNG Terminal (over-size drawings)

AGPA requests confidential treatment of information contained in Appendix II – Drawing/Plans Showing Bore Hole Locations for Anderson Bay, LNG Terminal (over-size drawings) to its AGIA Application.

The Drawing/Plans Showing Bore Hole Locations for Anderson Bay, LNG Terminal (over-size drawings) marked as Appendix II to AGPA's AGIA application consists of and contains proprietary information (as defined by AS 43.90.900 (20) and Trade Secrets (as defined by AS 45.50.940 (3)). The Drawing/Plans Showing Bore Hole Locations for Anderson Bay, LNG Terminal (over-size drawings) contain proprietary information and valued intellectual property and release of this information would cause significant damage to AGPA and its project. There is no question that release of the information ". . . would adversely affect the competitive position of the applicant or materially diminish the commercial value of the information to the applicant[.]" AS 43.90.900 (2). Moreover, the information ". . . derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use;" and ". . . is the subject of efforts that are reasonable under the circumstances to maintain its secrecy." AS 45.50.940 (3).

Brief non-confidential summary pursuant to AS 43.90.160:

The information contained in Appendix II – Drawing/Plans Showing Bore Hole Locations for Anderson Bay, LNG Terminal (over-size drawings) consists of detailed drawing of the LNG Terminal. Please note that the over-sized drawings of the Plans Showing Bore Hole Locations for Anderson Bay, LNG Terminal do not lend themselves to being copied with the proprietary or trade secret information redacted.

APPENDIX JJ

Anderson Bay LNG Plant & Terminal Site
Grid layout with preliminary borehole
And trench locations
Oversized drawing

[See Roll # 12]

THIS PAGE CONTAINS PROPRIETARY OR TRADE SECRET INFORMATION THAT IS CONFIDENTIAL TO THE PORT AUTHORITY, WHO REQUESTS THAT THE INFORMATION BE KEPT CONFIDENTIAL AND EXEMPT FROM PUBLIC DISCLOSURE TO THE EXTENT PROVIDED IN AS 43.90.150 & AS 43.90.160

Appendix JJ – Anderson Bay LNG Plant and Terminal Site, Grid Layout with Preliminary Borehole and Trench Locations (over-size drawings)

AGPA requests confidential treatment of information contained in Appendix JJ – Anderson Bay LNG Plant and Terminal Site, Grid Layout with Preliminary Borehole and Trench Locations (over-size drawings) to its AGIA Application.

The Anderson Bay LNG Plant and Terminal Site, Grid Layout with Preliminary Borehole and Trench Locations (over-size drawings) marked as Appendix JJ to AGPA's AGIA application consists of and contains proprietary information (as defined by AS 43.90.900 (20) and Trade Secrets (as defined by AS 45.50.940 (3)). The Anderson Bay LNG Plant and Terminal Site, Grid Layout with Preliminary Borehole and Trench Locations (over-size drawings) contain proprietary information and valued intellectual property and release of this information would cause significant damage to AGPA and its project. There is no question that release of the information ". . . would adversely affect the competitive position of the applicant or materially diminish the commercial value of the information to the applicant[.]" AS 43.90.900 (2). Moreover, the information ". . . derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use;" and ". . . is the subject of efforts that are reasonable under the circumstances to maintain its secrecy." AS 45.50.940 (3).

Brief non-confidential summary pursuant to AS 43.90.160:

The information contained in Appendix JJ – Anderson Bay LNG Plant and Terminal Site, Grid Layout with Preliminary Borehole and Trench Locations (over-size drawings) consist of detailed drawings of the Anderson Bay LNG Plant and Terminal Site, Grid Layout with Preliminary Borehole and Trench Locations shown. Please note that the Anderson Bay LNG Plant and Terminal Site, Grid Layout with Preliminary Borehole and Trench Locations are over-sized and do not lend themselves to being copied with the proprietary or trade secret information redacted.

APPENDIX KK

Pipeline drawing showing pipeline location
At elevation along Atigun River
And Atigun Camp

[See Roll # __]

THIS PAGE CONTAINS PROPRIETARY OR TRADE SECRET INFORMATION THAT IS CONFIDENTIAL TC THE PORT AUTHORITY, WHO REQUESTS THAT THE INFORMATION BE KEPT CONFIDENTIAL AND EXEMPT FROM PUBLIC DISCLOSURE TO THE EXTENT PROVIDED IN AS 43.90.150 & AS 43.90.160

Appendix KK – Pipeline Drawing Showing Pipeline Location at elevation along Atigun River and Atigun Camp

AGPA requests confidential treatment of information contained in Appendix KK – Pipeline Drawing Showing Pipeline Location at elevation along Atigun River and Atigun Camp to its AGIA Application.

The Pipeline Drawing Showing Pipeline Location at elevation along Atigun River and Atigun Camp marked as Appendix KK to AGPA's AGIA application consists of and contains proprietary information (as defined by AS 43.90.900 (20) and Trade Secrets (as defined by AS 45.50.940 (3)). The Pipeline Drawing Showing Pipeline Location at elevation along Atigun River and Atigun Camp contain proprietary information and valued intellectual property and release of this information would cause significant damage to AGPA and its project. There is no question that release of the information ". . . would adversely affect the competitive position of the applicant or materially diminish the commercial value of the information to the applicant[.]" AS 43.90.900 (2). Moreover, the information ". . . derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use;" and ". . . is the subject of efforts that are reasonable under the circumstances to maintain its secrecy." AS 45.50.940 (3).

Brief non-confidential summary pursuant to AS 43.90.160:

The information contained in Appendix KK – Pipeline Drawing Showing Pipeline Location at elevation along Atigun River and Atigun Camp consists of detailed drawing of the Pipeline Location at elevation along both the Atigun River and the Atigun Camp. Please note that the Pipeline Drawing Showing Pipeline Location at elevation along Atigun River and Atigun Camp does not lend itself to being copied with the proprietary or trade secret information redacted.

APPENDIX LL

AOGCC Report re Rule 9
July 10, 2007

STATE OF ALASKA
ALASKA OIL AND GAS CONSERVATION COMMISSION
333 West 7th Avenue, Suite 100
Anchorage, Alaska 99501

Re:	Inquiry into amending Rule 9 ("Pool Off-Take Rates"), CO 341D, for the Prudhoe Oil Pool, Prudhoe Bay Field)	Prudhoe Oil Pool Prudhoe Bay Field July 10, 2007

REPORT OF THE COMMISSION INQUIRY
INTO AMENDING RULE 9 ("POOL OFF-TAKE RATES"), CO 341D,
FOR THE PRUDHOE OIL POOL, PRUDHOE BAY FIELD

On June 19, 2007, the Alaska Oil and Gas Conservation Commission ("Commission") held a public hearing (pursuant to AS 31.05.030(b)) to consider amending Rule 9 ("Pool Off-Take Rates") of Conservation Order ("CO") 341D for the Prudhoe Oil Pool, Prudhoe Bay Field, to require approval of a depletion plan prior to a significant gas offtake. This report presents the Commission's conclusions:

- No change in Rule 9 is necessary at this time.
- Prudhoe Bay operator must demonstrate, through existing reporting mechanisms, that they are implementing near-term strategies to maximize oil recovery prior to gas sales.

Rule 9 (which is among the Prudhoe Oil Pool pool rules that the Commission adopted in 1977) limits gas offtake from the Prudhoe Oil Pool to 2.7 billion standard cubic feet per day ("bscfd"). Because of the likelihood that Prudhoe Oil Pool gas will eventually be part of major gas sales, the Commission decided, in 2005, to investigate the need to update Rule 9 given the reservoir's development and information that has become available since 1977. Public hearings regarding revising Rule 9 were held on March 3, 2005, and May 19, 2005. In a December 5, 2005, report, the Commission noted that the Prudhoe Working Interest Owners ("WIOs") had agreed to provide access to their reservoir simulation and engineering studies so that the Commission could analyze the affects of different gas offtake rates and gas sales startup dates on total hydrocarbon recovery from the Prudhoe Oil Pool.

Based on reservoir model evaluations and studies provided by the WIOs, on February 15, 2007, Blaskovich Services, Inc., a reservoir engineering consultant, provided the Commission a confidential study on the potential impacts of major gas sales on hydrocarbon recovery from the Prudhoe Oil Pool ("Gas Offtake Study"). Oral and written summaries of the study were presented at a February 28, 2007, public hearing.

The Gas Offtake Study found insufficient information on which to justify increasing the offtake rate above 2.7 bscfd, but concluded that an early, high rate gas sale could result in the loss of a substantial volume of hydrocarbons, but even greater volumes could be lost if gas sales are too delayed. The study noted that offtake from gas sales is at least 8 years away. The study included several recommendations. First, before commitments to sell gas are made, to evaluate the potential impact of the offtake on total hydrocarbon recovery, a hydrocarbon depletion plan should be developed; the plan should take into account the offtake startup date, offtake rate, and liquid loss mitigation efforts. Second, to maximize total hydrocarbon recovery, the field should be prepared for gas sales through the implementation of near-term strategies that focus on increasing oil recovery prior to gas offtake and ensuring that facility and well downtime are minimized. Third, the Commission should receive periodic updates on the depletion planning efforts.

Following up on the recommendations of the Gas Offtake Study, at the June 19, 2007, public hearing, the Commission's staff proposed adding to Rule 9 the following: "Prior to committing gas for sale during a binding open season process, the operator must obtain approval from the Commission of a depletion plan that insures a greater ultimate recovery and prevents waste of oil and gas." The Commission's consultant, who prepared the study, explained how the proposed amendment was consistent with the recommendations. Also, the Commission received oral and written testimony on the proposed amendment from the field operator and members of the public.

Based on the Gas Offtake Study and multiple hearings regarding Rule 9, the Commission has decided—at this time—not to amend the rule to require a Commission-approved hydrocarbon depletion plan prior to a gas sale. First, given that any major gas offtake as a result of a gas sale is still many years away, amending Rule 9 now to require such a plan is unnecessary; second, even in the absence of such a plan, the waste of oil and gas—including the waste of oil for gas—is prohibited pursuant to AS 31.05.095; third, the Commission already receives depletion plan-related information in the WIOs' annual surveillance report (which is required pursuant to CO 341D Rule 11), annual plan of development (which is required by the Department of Natural Resources ("DNR")), and annual field overview presentation (which is also required by DNR); and fourth, at the time (if ever) that an amendment is sought to increase the 2.7 bscfd gas offtake rate, Rule 9 can be amended to include a depletion plan requirement.

By not now taking action to amend Rule 9, the Commission retains the right to again consider requiring a Commission-approved hydrocarbon depletion plan prior to any major gas sales or to impose any other requirements that are consistent with the conclusions and recommendations of the Gas Offtake Study as part of any future amendment to Rule 9.

This inquiry is terminated.

DONE at Anchorage, Alaska, and Dated July 10, 2007

John K. Norman Chairman	Daniel T. Seamount, Jr. Commissioner	Cathy P. Foerster Commissioner

APPENDIX MM

Letter of Intent Regarding Project Labor Agreement

411 4th Avenue
Fairbanks, AK 99701
Phone: (907) 474-2011
Fax: (907) 474-2001

www. allalaskagasline .com

November 30, 2007

This **LETTER OF INTENT** is intended to reflect the Alaska Gasline Port Authority's intent to negotiate and execute a collective bargaining agreement in the form of a Project Labor Agreement for all project work awarded to the licensee or its agents under the AGIA.

- Use of modernized technology with proven results of quality and integrity to increase productivity and efficiency.
- Incorporation of "pre-job" meetings where all aspects of a particular work process are explained and jurisdictional assignments are made; thus lessening the opportunity for workplace disruptions due to mis-assignments.
- Bright lines established for work done under the auspices of the building trades and work under the auspices of the pipeline crafts.
- Union security clause to assure inclusiveness for all qualified workers.
- Use of composite crews where appropriate.
- Development of a formula to assure that wage and benefits and other economic factors are known for the duration of the project.
- Incorporation of methods for complying with Sections 28 and 29 of the Right of Way Statutes which govern the authority to operate within the ROW. Including incorporation of language similar to the language included in the current Labor Agreement with the Alyeska Pipeline Service Company maintenance and construction contractors which has been highly successful in providing career opportunities to Alaskan Natives.
- While the Letter of Intent identified the intention of the parties to utilize the original TAPS Project Labor Agreement as a template; the parties recognize that the following areas either were originally not recognized or were recognized but not deemed important. We intend to craft language to:
    - Allow pre-employment drug and alcohol testing;
    - Treat safety as a number one priority;
    - Allow for background checks;
    - Deal with HIRD issues (harassment, intimidation, retaliation, and discrimination)

Alaska Gasline Port Authority

By: ______________________
Chairman

Alaska AFL.CIO Building Trades Councils

DENNIS D. TRAYLOR, ANCHORAGE
Jay Quakenbush Fairbanks
Mike Nolan, Juneau VP

By: Vince Beltrami, President AK AFL-CIO
President

Alaska Petroleum Joint Crafts Council

By: ______________________
President

Alaska Works

By: ______________________
Mike Andrews

Alaska Gasline PORT AUTHORITY

411 4th Avenue
Fairbanks, AK 99701
Phone: (907) 474-2011
Fax: (907) 474-2001

www. allalaskagasline .com

November 30, 2007

Gentlemen:

Through this **Letter of Intent** the Port Authority and the undersigned parties agree to collaborate in developing the process and goals towards achieving Alaska Hire and Training in all project phases; pre-construction, construction and post-construction. To be included as appropriate in the PLA.

A. Maximum use of hiring hall procedures to assure that qualified Alaska/local hire is accomplished to the fullest extent possible under law.

B. Identifying Alaskan Contractors for contracts or subcontracts on this project by working with contractor associations such as but not limited to the Alaskan-Associated General Contractors, National Electrical Contractors Association and the National Mechanical Association.

C. Continued use of hiring hall, both virtual and mortar/bricks, which currently cover the entire State of Alaska.

D. Continued partnership with Alaska Works and others to identify and train journey and apprentice workers in rural and urban Alaska. Participation to as full extent as appropriate with AK DOL programs existing today and working with the Department in developing processes and programs in the future.

E. Alaska hire to emphasize training the Alaskan workforce for the next generation. Recruitment, classroom training and on-the-job experience to take place for pre-construction infrastructure, construction undertaken by the licensee under AGIA, maintenance of operational structures and pipelines, and training for opportunities post construction not covered under this PLA. Recruitment to emphasize rural Alaskan, K-12 and post secondary schools and institutions. Additional emphasis on our helmets to hardhats program to develop construction career opportunities for returning veterans.

- Maximum use of hiring hall procedures to assure that qualified Alaska/local hire is accomplished to he fullest extent possible under law.

We look forward to working with you towards accomplishing our mutual goals of finally commercializing Alaska's vast resources of natural gas.

Alaska Gasline Port Authority

By: ______________________
Chairman

Alaska AFL.CIO Building Trades Councils

DENNIS D. TRAYLOR, ANCHORAGE
Jay Quakenbush Fairbanks
Mike Nofar, JUNEAU N.S.
By: Vince Beltrami, Pres. AK AFL-CIO
President

Alaska Petroleum Joint Crafts Council

By: ______________________
President

APPENDIX NN

AGPA Financial Model
(provided in Excel
format on electronic CD

APPENDIX NN

AGPA Financial Model
(provided in Excel
format on electronic CD

Appendix NN – Financial Model for the All Alaska Gas Pipeline

AGPA requests confidential treatment of information contained in Appendix NN – Financial Model for the All Alaska Gas Pipeline to its AGIA Application.

The Financial Model for the All Alaska Gas Pipeline marked as Appendix NN to AGPA's AGIA application consists of and contains proprietary information (as defined by AS 43.90.900 (20) and Trade Secrets (as defined by AS 45.50.940 (3)). The Financial Model for the All Alaska Gas Pipeline contains proprietary information and valued intellectual property and release of this information would cause significant damage to AGPA and its project. Portions of Appendix NN have been received by companies outside of AGPA under the understanding that the analysis would remain confidential. There is no question that release of the information ". . . would adversely affect the competitive position of the applicant or materially diminish the commercial value of the information to the applicant[.]" AS 43.90.900 (2). Moreover, the information ". . . derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use;" and ". . . is the subject of efforts that are reasonable under the circumstances to maintain its secrecy." AS 45.50.940 (3).

Brief non-confidential summary pursuant to AS 43.90.160:

The information contained in Appendix NN – Financial Model for the All Alaska Gas Pipeline consists of a detailed breakdown of the financial analysis of building and operating the All Alaska Gas Pipeline. Please note that the information contained in Appendix NN – Financial Model for the All Alaska Gas Pipeline does not lend itself to being copied with the proprietary or trade secret information redacted.